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Request IR-4:

With respect to the Opinion of Capital Structure and Return on Equity, prepared by Ms. Kathleen C. McShane, and to the extent that these materials are not provided in IRs 1-3, and with reference to Section F, pages 15-21, please provide:

(a) **Copies of all data, source documents, and work papers used in the development of the proposed ROE adjustment mechanism for the years 2014 to 2017;**

(b) **Copies of all testimony prepared by Ms. McShane in which she has proposed a ROE adjustment mechanism for a gas or electric utility;**

(c) **A copy of the reports cited in footnote nos. 25 and 26;**

(d) **Copies of all studies known to Ms. McShane which evaluate and/or assess the forecasts of government and utility bond yields by *Consensus Forecasts*.**

For the Microsoft Excel copies in (a), please keep all formulas intact.

Response IR-4:

(a) Please see response to CA IR-1 and CA IR-3.

(b) Please see response to CA IR-8.

(c) The requested documents were provided in response to CA IR-1, Attachments 25, 37 and 38.

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(d) Ms. McShane is not aware of any studies which evaluate and/or assess the forecasts of government and utility bond yields by *Consensus Forecasts*.

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Request IR-5:

With respect to the Opinion of Capital Structure and Return on Equity, prepared by Ms. Kathleen C. McShane, and with respect to Appendix B, page B-4, please:

(a) List the utility companies considered for inclusion as indicated in Criteria 1; and

(b) The utility companies eliminated by criteria 2, 3, 4, 5, and 6, along with the company figures and/or values that caused the companies eliminated by the screen.

Response IR-5:

Please refer to Attachment 1.

Criteria 1 Companies

AGL Resources
ALLETE
Alliant Energy
Amer. Elec. Power
Ameren Corp.
Atmos Energy
Avista Corp.
Black Hills
Cen. Vermont Pub. Serv.
CenterPoint Energy
CH Energy Group
Cleco Corp.
CMS Energy Corp.
Consol. Edison
Constellation Energy
Dominion Resources
DTE Energy
Duke Energy
Edison Int'l
El Paso Electric
Empire Dist. Elec.
Entergy Corp.
Exelon Corp.
FirstEnergy Corp.
G't Plains Energy
Hawaiian Elec.
IDACORP, Inc.
Integrys Energy
ITC Holdings
Laclede Group
MGE Energy
New Jersey Resources
NextEra Energy
NiSource Inc.
Northeast Utilities
Northwest Nat. Gas
NV Energy Inc.
OGE Energy
Otter Tail Corp.
Pepco Holdings
PG&E Corp.
Piedmont Natural Gas
Pinnacle West Capital
PNM Resources
Portland General
PPL Corp.
Progress Energy
Public Serv. Enterprise
SCANA Corp.
Sempra Energy
South Jersey Inds.
Southern Co.
Southwest Gas
TECO Energy
UGI Corp.
UIL Holdings
UniSource Energy
Vectren Corp.
Westar Energy
WGL Holdings Inc.
Wisconsin Energy
Xcel Energy Inc.

Criteria 2 - Eliminated Companies	S&P Debt Rating	Moody's Debt Rating
Amer. Elec. Power	BBB	
Ameren Corp.	BBB-	
Avista Corp.	BBB	
Black Hills	BBB-	
Cen. Vermont Pub. Serv.	NA	Baa3
CenterPoint Energy	BBB+	Baa3
Cleco Corp.	BBB	
CMS Energy Corp.	BBB-	
Constellation Energy	NA	Baa2
Dominion Resources	A-	Baa2
DTE Energy	BBB+	Baa2
Duke Energy	A-	Baa2
Edison Int'l	BBB-	
El Paso Electric	BBB	
Empire Dist. Elec.	BBB-	
Entergy Corp.	BBB	
Exelon Corp.	BBB	
FirstEnergy Corp.	BBB-	
G't Plains Energy	BBB	
Hawaiian Elec.	BBB-	
IDACORP, Inc.	BBB	
ITC Holdings	BBB+	Baa2
Laclede Group	A	Baa2 (P)
NiSource Inc.	BBB-	
Northeast Utilities	A-	Baa2
NV Energy Inc.	BB+	
Otter Tail Corp.	BBB-	
Pepco Holdings	BBB+	Baa3
PG&E Corp.	BBB	
Pinnacle West Capital	BBB	
PNM Resources	BBB-	
Portland General	BBB	
PPL Corp.	BBB	
Progress Energy	BBB+	Baa2
Public Serv. Enterprise	BBB	
SCANA Corp.	BBB+	Baa3
South Jersey Inds.	BBB+	Baa1 (South Jersey Gas Company)
TECO Energy	BBB+	Baa2
UGI Corp.	NA	NA
UIL Holdings	BBB	
UniSource Energy	NA	Ba1
Westar Energy	BBB	

Criteria 3 - Out on Dividend Cut

Southwest Gas	Dividend cut 2003

Criteria 4 - Out on Merger Activity

CH Energy Group	Target of Fortis Inc. acquisition

Criteria 5 - Out on Utility Asset Percentage <80%	**Utility Assets (2010)**
MGE Energy	72.0%
New Jersey Resources	72.7%
NextEra Energy	56.2%
OGE Energy	65.7%
Sempra Energy	67.2%

Criteria 6 - Availability of Forecasts

na

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Request IR-6:

With respect to Appendix 4.01 Financial Model, please provide:

(a) Copies of all data, source documents, assumptions, and work papers used in the development of the 4.0% interest rate on the debt; and

(b) Microsoft Excel copies of the data, calculations, work papers, and other analyses used in the development of the 4.0% interest rate on the debt, with formulas intact.

Response IR-6:

(a) Data is provided in part (b) below.

(b) The attached spreadsheet (CA IR-6 Att 1) outlines the development of the 4.0% interest rate on the debt with formulas intact as requested.

The 4.0 percent interest rate was developed as follows:

(i) The average of available forecasts for the Government of Canada 30 year bond rate for the fourth quarter of 2013 as this is the expected timing for the financial close.

(ii) An estimate of the basis point differential or ‘spread’ between a true Government of Canada 30 year bond versus a federally guaranteed bond using market based pricing for a Canada Post 30 year bond rate as a proxy. Lenders price this spread into a Canada Post bond because it is a Crown Corporation and not the sovereign credit (Government of Canada). As NSPML is also a corporation with the distinction of having its debt federally guaranteed by the Government of Canada,

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it is reasonable to assume that lenders will price a basis point differential or spread similar to Canada Post.

(iii) Liquidity premium and Federal Loan Guarantee financing structure – Liquidity premium may be required by lenders for debt issuances less than $500 million. The discrete issuance sizes may be less than $500 million if the Maritime Link is financed with multiple debt issuances or tranches over the construction cycle. The Federal Loan Guarantee financing structure may result in incremental costs in terms of basis points.

(iv) Amortizing Premium – Premium will be required as a result of amortizing the debt and paying down over the 35 year term (as opposed to an interest only loan with a large single repayment at maturity).

FLG - 35 years	30 years	Comments
GoC	3.00%	Average of Q4 2013 Forecast (with Conf. Board of Cda) **(Note 1)**
Bullet	3.00%	No basis points for additional 5 years interpolated
	0.55%	Spread over direct draw on Consolidated Revenue Fund (based on Cda Post 30 year bullet)
	0.20%	Liquidity premium / FLG requirements (issues less than $500M / FLG conditions or covenants)
	3.75%	"Bullet" (non-amortizing coupon)
	0.25%	Amortizing premium required by lenders
Total	4.00%	

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Request IR-7:

For all rate cases referenced between pages 10-15 of the testimony of Ms. Kathleen C. McShane, please indicate:

(a) Whether or not these cases include a ROE automatic adjustment clause as proposed by Ms. McShane on pages 15-21 of her testimony; and

(b) For the cases in (1) that do have a ROE adjustment clause, please provide copies of the commission's order that specify the details of the adopted ROE and the ROE adjustment clause.

Response IR-7:

(a) Of the cases mentioned on pages 10-15 of Ms. McShane's testimony, Hydro One is currently subject to an automatic adjustment formula, that of the Ontario Energy Board. As stated on page 19 of Ms. McShane's testimony:

> NSPML's proposed formula effectively relies on the same variable as the Ontario Energy Board's automatic ROE adjustment formula, which it adopted in 2009. The OEB formula adjusts the allowed ROE by 50 percent of the difference between an initial specified long-term Government of Canada bond yield and a forecast long-term Government of Canada bond yield and 50 percent of the change between an initial specified long-term A-rated utility/Government of Canada bond yield spread and the prevailing spread at the time the formula is applied.[FN] Although the OEB formula is expressed with two separate variables (long-term Government bond yield and A-rated utility/Government bond yield spread), it collapses into a single variable, the long-term A-rated utility bond yield.

(b) The OEB's 2009 Report which sets out the formula to which Hydro One is subject was provided in response to CA IR-1, Attachment 25.

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Request IR-8:

With reference to Appendix A and the previous rate of return testimonies of Ms. Kathleen C. McShane, please:

(a) Indicate all cases in which Ms. Kathleen C. McShane has recommended a ROE automatic adjustment clause;

(b) For the cases in (1) in which Ms. McShane has recommended a ROE adjustment clause, provide copies of the testimonies; and

(c) For all cases in (1), provide a copy of the commission's order that specify the details of the adopted ROE and the ROE adjustment clause.

Response IR-8:

(a-c) Ms. McShane has presented cost of capital testimony in over 200 proceedings since 1987. To identify all of the requested information would be extremely onerous task. However, a review of the more than 50 cases in which Ms. McShane has appeared since 2003 (inclusive) was conducted and the requested testimonies in which Ms. McShane had proposed a formula and the related decisions are attached. A listing of the attached files is below:

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Case Reference	Decision File Name	Testimony File Name
Generic Cost of Capital, Alberta 2003	CA NSMLI NSPI 8 Attachment 1 EUB Generic Decision 2004-052.pdf	CA NSMLI NSPI 8 Attachment 2 McShane ATCO Utilities and AltaGas - July 2003.pdf
Enbridge Pipelines (Line 9) 2009	CA NSMLI NSPI 8 Attachment 3 NEB Line 9 settlement letter.pdf	CA NSMLI NSPI 8 Attachment 4 McShane Line 9 2009.pdf
FortisBC Energy Inc. 2005	CA NSMLI NSPI 8 Attachment 5 BCUC TGI Decision 2006.pdf	CA NSMLI NSPI 8 Attachment 6 McShane TGI 2005.pdf
Gazifère 2010	Previously filed as Attachment 37 in response to CA NSMLI NSPI 1	CA NSMLI NSPI 8 Attachment 7 McShane Gazifere 2010. pdf
Northland Utilities NWT 2008	CA NSMLI NSPI 8 Attachment 10 Decision NWT 2008.pdf	CA NSMLI NSPI 8 Attachment 8 Northlands NWT 2008.pdf
Northland Utilities YWK 2008	CA NSMLI NSPI 8 Attachment 11 Decision YWK 2008.pdf	CA NSMLI NSPI 8 Attachment 9 Northlands YWK 2008.pdf
Ontario Power Generation 2007	CA NSMLI NSPI 8 Attachment 12 OEB OPG EB-2007-0905.pdf	CA NSMLI NSPI 8 Attachment 13 McShane OPG 2007.pdf
Yukon Electrical Company 2008	CA NSMLI NSPI 8 Attachment 15 Decision YECL 2009.pdf	CA NSMLI NSPI 8 Attachment 14 McShane YECL 2008.pdf

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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ATCO ELECTRIC LTD. (TRANSMISSION)
ATCO GAS
ATCO PIPELINES
ENMAX POWER CORPORATION (DISTRIBUTION)
EPCOR DISTRIBUTION INC.
EPCOR TRANSMISSION INC. **Decision 2004-052**
FORTISALBERTA (FORMERLY AQUILA NETWORKS) **Application No. 1271597**
NOVA GAS TRANSMISSION LTD. **File No. 5681-1**

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.

[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]

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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]

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.

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

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[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.

Return Awards for Other Canadian Utilities

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.

<u>Return Awards for U.S. Utilities</u>

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

[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.

<u>Business Risk</u>

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.

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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.

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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.

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.

Conclusion

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

29. Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%. 53

30. 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%. 53

31. As determined above, the Board concludes that an appropriate common equity ratio for ATCO Gas is 38.0%. 53

32. Considering all of the above, the Board concludes that an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.......... 54

33. The Board concludes that there is no need for utility-specific adjustments to the common ROE for any of the Applicants.......... 54

34. 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 been a material change in investment risk since the time of this Proceeding, except as otherwise specifically directed in this Decision. 55

35. 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.......... 56

36. 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.......... 56

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)

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

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.

BD&P

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Calgary, Alberta
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Frank L. Burnet Q.C. (1890-1982)
Thomas J. Duckworth Q.C., Counsel

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. <u>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.</u> (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

National Energy Board | Office national de l'énergie

File OF-Tolls-Group1-E101-2011-05 01
15 September 2011

Ms. Margery Fowke
Senior Regulatory Counsel
Enbridge Pipelines Inc.
425 – 1st Street S.W.
Calgary, AB T2P 3L8
Facsimile 403-767-3863

Dear Ms. Fowke:

Enbridge Pipelines Inc. (Enbridge) Line 9 Settlement Agreements Application (the Application)

The National Energy Board (the Board) has received Enbridge's Application dated 23 June 2011. The Application included a request for approval of the 2008, 2009 and 2010 Amended Agreement to be made effective 14 June 2011. Enbridge also applied for approval of the 2011 and Beyond Amended Agreement to be made effective 14 June 2011. The Board acknowledges that as part of the Application, Enbridge has withdrawn its application dated 1 December 2010 with respect to Line 9 Settlement Agreements (NEB File OF-Tolls-Group1-E101-2010-08 01). Enbridge states that the Application replaces the 1 December 2011 application.

Enbridge requested that the Board approve the 2008, 2009 and 2010 Amended Agreement only if the 2011 and Beyond Amended Agreement and the Competitive Toll Settlement (CTS), a separate application filed by Enbridge with the Board on 2 May 2011, were also approved. Likewise, Enbridge requested that the Board approve the 2011 and Beyond Amended Agreement only if the 2008, 2009 and 2010 Amended Agreement and the CTS were also approved. The Board notes that on 23 June 2011, the Board issued Order TO-03-2011, approving the CTS.

The Board has examined the 2008, 2009 and 2010 Amended Agreement and the 2011 and Beyond Amended Agreement (the Agreements) and determined that they are consistent with the *Revised Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs* dated 12 June 2002.

The Board is satisfied that Enbridge has calculated the 2008-2011 tolls in accordance with the Agreements and that the resulting tolls are just and reasonable in accordance with Part IV of the *National Energy Board Act*. The Board notes that letters of support were received from Imperial Oil Limited and NOVA Chemicals (Canada) Ltd.

…/2

The Board notes that Enbridge has requested an exemption from provisions of the *Oil Pipeline Uniform Accounting Regulations* (OPUAR) to allow Enbridge to maintain its general ledger according to its own chart of accounts. Enbridge has also requested an exemption from the NEB Filing Manual requirements. Instead, Enbridge proposes to file annual audited consolidated financial statements. The Board has considered the relatively short time frame of the settlement and has approved these requests. However, the Board directs Enbridge to file audited consolidated financial statements on an annual basis, as described in the attached Order.

The Board's approval of the Application, set out in Order TO-004-2011, is attached.

Enbridge is directed to serve a copy of this letter and the attached Order on Line 9 and Mainline shippers, and interested persons.

Yours truly,

AnneMarie Erickson

Anne-Marie Erickson
Secretary of the Board

Attachment

National Energy Board | Office national de l'énergie

ORDER TO-004-2011

IN THE MATTER OF the *National Energy Board Act* (the Act) and the regulations made thereunder; and

IN THE MATTER OF an application by Enbridge Pipelines Inc. (Enbridge) dated 23 June 2011 for approval of final Line 9 tolls pursuant to Part IV of the Act filed with the National Energy Board (Board) under File OF-Tolls-Group1-E101-2011-05 01 (the Application).

BEFORE the Board on 15 September 2011.

WHEREAS the Board has issued multiple interim Orders for the Line 9 system, which commenced effective 1 January 2008;

AND WHEREAS Appendix A of this Order (Appendix A) describes the interim Orders issued by the Board, the effective dates of these interim Orders, and the corresponding Tariffs which contain the tolls charged by Enbridge during the effective dates of the Orders;

AND WHEREAS in addition to the Orders described in Appendix A, the Board issued Order TOI-01-2009 for Enbridge Tariff 290 to be made interim effective 1 May 2009, and Order TOI-02-2009 for Enbridge Tariff 291 to be made interim effective 1 January 2008 through 30 April 2009;

AND WHEREAS on 23 June 2011, Enbridge filed the Application for approval of the Tariffs 298, 299, 300, 301, 302, 310, 311, 312, 319 and 320 (the Tariffs) and final tolls calculated in accordance with the Tariffs, as described in Appendix A;

AND WHEREAS as part of the Application, Enbridge requested approval of the Line 9 Amended Tolls Settlement Agreement for the Years 2008, 2009, and 2010 (Agreement A) and tolls calculated in accordance with Agreement A as described in Appendix A;

AND WHEREAS as part of the Application, Enbridge requested approval of the Line 9 Amended Settlement Agreement for the Years 2011 and Future Years (Agreement B) and tolls calculated in accordance with Agreement B as described in Appendix A;

.../2

AND WHEREAS as part of the Application, Enbridge requested approval of Tariff No. 297, effective 1 August 2011;

AND WHEREAS as part of the Application, Enbridge withdrew its application dated 1 December 2010 with respect to Line 9 Settlement Agreements (NEB File OF-Tolls-Group1-E101-2010-08 01);

AND WHEREAS Enbridge notified interested persons of its Application and advised interested persons that they may file comments with the Board within 10 calendar days of the date of the Application;

AND WHEREAS letters of support were received from Imperial Oil Limited and NOVA Chemicals (Canada) Ltd.;

AND WHEREAS no person opposed the Application;

THEREFORE, IT IS ORDERED THAT pursuant to section 20, Part IV, and subsection 129(1.1) of the Act:

1. Agreements A and B are approved;
2. The tolls calculated in accordance with the Tariffs and Agreements A and B are just and reasonable and approved as final tolls as described in Appendix A;
3. Tariff Nos. 290 and 291 are approved as final;
4. Tariff No. 297 is approved as final effective 1 August 2011;
5. Enbridge is relieved from the requirement to keep the system of accounts as prescribed by the *Oil Pipeline Uniform Accounting Regulations*;
6. Enbridge is relieved from the requirement to comply with the reporting and filing requirements set forth in the Board's Filing Manual, Guide BB entitled Financial Surveillance Reports; and
7. Enbridge shall file audited consolidated financial statements on an annual basis.

NATIONAL ENERGY BOARD

AnneMarie Erickson

Anne-Marie Erickson
Secretary of the Board

Appendix A

Tolls covered in the Toll Order				
Tariff	Replaces	Order	Effective	
280	273	TOI-04-2007	01-Jan-08	
292	280	TOI-02-2009	01-Jan-08	31-Mar-08
298	292	Agreement A	01-Jan-08	31-Mar-08
284	280	TOI-01-2008	01-Apr-08	
		AO-1-TOI-01-2008	05-Sep-08	
293	284	TOI-02-2009	01-Apr-08	31-Dec-08
299	293	Agreement A	01-Apr-08	31-Dec-08
285	284	TOI-03-2008	01-Jan-09	
294	285	TOI-02-2009	01-Jan-09	31-Mar-09
300	294	Agreement A	01-Jan-09	31-Mar-09
295	294	TOI-02-2009	01-Apr-09	30-Apr-09
289	285	TOI-01-2009	01-May-09	
301	295&289	Agreement A	01-Apr-09	31-Dec-09
302	289	Agreement A	01-Jan-10	11-Apr-10
308	289	TOI-02-2010	12-Apr-10	
310	308	Agreement A	12-Apr-10	05-Aug-10
309	308	TOI-03-2010	06-Aug-10	
311	309	Agreement A	06-Aug-10	31-Dec-10
312	309	Agreement B	01-Jan-11	31-Mar-11
315	309	TOI-03-2011	01-Apr-11	
319	315	Agreement B	01-Apr-11	30-Jun-11
318	315	TOI-04-2011	01-Jul-11	
320	318	Agreement B	01-Jul-11	

Agreement A: 2008, 2009 and 2010 Amended Agreement
Agreement B: 2011 and Beyond Amended Agreement

NATIONAL ENERGY BOARD

IN THE MATTER OF the *National Energy Board Act* and the Regulations made under it; and

IN THE MATTER OF an Application by Enbridge Pipelines Inc. pursuant to Part IV of the *National Energy Board Act* for the approval of tolls and tariffs for westbound service on its Line 9.

ENBRIDGE PIPELINES INC.

APPENDIX A-7.2 TO LINE 9 APPLICATION

Expert Evidence – Prepared Testimony of Kathleen C. McShane (Foster Associates, Inc.)

ENBRIDGE PIPELINES INC.
LINE 9

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
December 2009

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of oil and gas pipelines, electric utilities, local gas distribution utilities, and telephone companies, in more than 200 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Enbridge Pipelines Inc. ("Enbridge Pipelines") owns and operates the Enbridge System which is comprised of three segments; one of them is Line 9, which transports liquid petroleum from Montréal, Québec to Sarnia, Ontario.[1] The Line 9 assets are described in Appendices A-1 and A-4 to Enbridge's application for final tolls and tariffs for 2008, 2009 and 2010.[2] I have been asked by Enbridge Pipelines to assess the reasonableness of its proposed capital structure and recommend a rate of return on equity ("ROE") for its Line 9 operations on a stand-alone basis; that is, as if Enbridge Pipelines' only business were owning and operating Line 9. I use the term "Enbridge" for this purpose. My conclusions are summarized below.

1. The proposed common equity ratio of 50% for Enbridge is reasonable based on:

    (a) its relative business risks;
    (b) capital structure guidelines issued by the debt rating agencies;
    (c) the allowed and actual capital structures maintained by other oil pipelines regulated by the National Energy Board ("NEB").

[1] The other two segments for toll-making purposes are the Older System and the Oil Products Transportation System (Line 8).
[2] Line 9 was formerly known as the Montréal Extension when it was in west to east service.

2. The point of departure for estimating the fair ROE for Enbridge for 2008, 2009, and 2010 is based on a proposed benchmark pipeline ROE formula which incorporates:

   (a) The initial ROE established in RH-2-94 by the NEB;
   (b) A correlation factor between the forecast long-term Government of Canada bond yield and the ROE of 0.50%; and
   (c) A correlation factor between the spread between long-term A rated corporate and Government of Canada bond yields and the ROE of 0.50%.

3. The indicated benchmark pipeline ROEs for 2008, 2009 and 2010 are 10.13%, 10.73% and 10.30% respectively.

4. The incremental equity risk premium for Enbridge relative to the benchmark pipeline ROE was estimated at 175-200 basis points, producing (at the mid-point) recommended ROEs for each of the test years as follows:

Table 1

Year	ROE
2008	12.00%
2009	12.60%
2010	12.18%

II. BACKGROUND

Line 9 was originally built in 1976 with Government of Canada financial support to transport Western Canadian crude oil to Montréal refineries in order to provide additional security of supply, as well as to Lévis (opposite Québec City) and Atlantic Canada refineries via ship from Montréal. In 1997, Enbridge, then Interprovincial Pipe Line Inc., applied to the NEB to reverse Line 9 to permit transportation of off-shore crude to Ontario refineries. The proposed reversal was backed by an eight-year Facilities Support Agreement as amended ("FSA") between Enbridge and four Ontario refiners (the "FSA Shippers") that would be the principal shippers on Line 9. The FSA took effect on October 1, 1999 after Line 9 went into reversed service. It included two distinct terms, the Primary Term, which covered the first five years of operation of Line 9 as reversed, and the Extended Term, which covered years six to eight. The FSA expired on September 30, 2007.

The first five years of the FSA were a transition period during which the tolls on Line 9 were charged largely on a stand-alone basis, but with some aspects of integration with the "Older System".[3] The FSA specified the common equity ratio and ROE that were to apply during the Primary Term: the deemed common equity ratio was set at 40% for Year 1, increasing to 45% in Year 5 by 1.25 percentage point increments; and, the ROE for each of the five years would be the multi-pipeline ROE for Group 1 oil and gas pipelines as determined each year in accordance with the automatic adjustment formula that was adopted in RH-2-94.

For the Extended Term, the FSA specified that (1) the tolls would be calculated on a stand-alone basis; (2) the FSA Shippers would have unapportioned access and rights to transportation based on their historical shipments, and (3) the capital structure would be determined in accordance with the last determination of the NEB. Enbridge entered into letter agreements during the Extended Term with the FSA Shippers that provided for

[3] The purpose of the integration was to have the benefits and risks of reversal shared between the Older System shippers and the FSA Shippers, while Enbridge was kept whole in respect to its Line 9 costs.

interim tolls with, when the tolls were made final, full recovery of deviations between forecast and actual costs for the two periods covering October 1, 2004 to March 31, 2005 and April 1, 2005 to March 31, 2006. The interim tolls were made final for each period by NEB Orders TO-03-2006 (April 13, 2006) and TO-05-2006 (June 29, 2006), respectively.

In April 2007, Enbridge, which had been operating on interim tolls since April 2006, applied to the NEB for, and obtained approval of, final tolls for the periods commencing April 1, 2006 and January 1, 2007. In September 2007, Enbridge withdrew its application, having reached agreement with Imperial Oil Limited ("Imperial") on a "Term Sheet" that outlined the terms and conditions for a new Transportation Service Agreement ("TSA") for westbound service on Line 9 during a five-year term and having agreed to conduct an open season for other shippers, such as NOVA Chemicals (Canada) Ltd. ("NOVA Chemicals"), that wanted westbound service on Line 9 on the same terms and conditions. In December 2007, following the completion of the open season, Enbridge applied for approval of toll principles as prescribed in the TSA and for interim and then final tolls commencing January 1, 2008.[4] The NEB set down this application for hearing in June 2008. Prior to the hearing, Enbridge applied to the NEB for, and obtained approval of, final tolls for the periods commencing April 1, 2006 and January 1, 2007. The NEB subsequently rescheduled the TSA-related hearing to January 2009. On April 2, 2009, the NEB denied Enbridge's application for the approval of the TSA's toll principles and for the resulting tolls.

As a result of the NEB's decision, Enbridge has been operating on interim tolls since January 1, 2008. The current application before the Board is being made to set final tolls for the three periods commencing January 1, 2008, January 1, 2009 and January 1, 2010.

[4] Final tolls for the two interim periods covering April 1, 2006 to December 31, 2007 were approved by NEB Order TO-03-2008 on April 21, 2008.

III. FAIR RETURN STANDARD

The standard for a fair return arises from legal precedents[5] which are echoed in numerous regulatory decisions across North America, including the NEB's *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008, March 2009* ("TQM"). As stated in the decision:

> The Board has considered the arguments put forward by TQM and CAPP and continues to believe that the legal framework for determining a fair return is as set out in Chapter 2 of the RH-2-2004, Phase II Decision. The Board notes that these views were based on the Federal Court of Appeal Decision in *TransCanada v. NEB*.
>
> When using the cost of service approach to determine tolls, the cost of capital is determined using the Board's sound judgment. Often the largest and therefore most important portion of cost of capital is the overall return on equity. While customers and consumers have an interest in ensuring that the cost of equity is not overstated, in the Board's view, this is factored in by having intervenors test and challenge the position the company has put forward. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. In the Board's view, the Federal Court of Appeal was clear that the overall return on equity 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.
>
> Therefore, the Board reaffirms the Fair Return Standard as articulated on page 17 of the RH-2-2004, Phase II Decision. The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

[5] The principal court cases in Canada and the U.S. establishing the standard include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission)*, [1960] S.C.R. 837; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, (262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).

The precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the pipeline can attract capital on reasonable terms and conditions, its financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk.

IV. ANALYTICAL FRAMEWORK

My analysis starts with the proposition that the fair return (which in this context encompasses both capital structure and ROE) for Enbridge should be determined on a stand-alone basis. The stand-alone principle encompasses the notion that the cost of capital incurred by tollpayers should be equivalent to that which would be faced by the pipeline raising capital in the public markets on the strength of its own business and financial parameters. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources and avoid cross-subsidies. The stand-alone principle has been respected by virtually every Canadian regulator, including the NEB, in setting both regulated capital structures and allowed ROEs. For the Extended Term under the now terminated FSA, the stand-alone principle was explicitly applied to Enbridge in the determination of tolls. The stand-alone principle is equally applicable to periods subsequent to the termination of the FSA.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm. For regulated companies like pipelines, the business risks also include regulatory risks, that is, the regulatory framework under which the pipeline operates. The prevailing regulatory framework effectively represents the current allocation of the fundamental business risks between investors and tollpayers. Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risks.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine a fair rate of return on rate base. The first is to assess the "subject" pipeline's business risks, then establish a capital structure that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone investment grade debt rating; and (c) would approximately equate the level of the specific pipeline's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of a single "benchmark" cost of equity to the subject pipeline without any adjustment to the ROE.

The second approach relies on acceptance of the pipeline's actual or proposed deemed capital structure for regulatory purposes. The actual or deemed capital structure then becomes the key measure of the pipeline's financial risks. The pipeline's level of total risk (business plus financial) is then compared against that faced by the proxy firms used to estimate the ROE requirement. If the total risk of the benchmark sample is higher or lower than that of the subject pipeline, an adjustment to their cost of equity would be required when setting the subject pipeline's allowed ROE.

Both of these approaches have been taken by regulators in Canada. The first approach was employed by the NEB when it established its automatic adjustment mechanism for a number of Group 1 oil and gas pipelines in the RH-2-94 proceeding. The individual pipelines were given deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark ROE could be applied across all of the pipelines. In two subsequent decisions for TransCanada PipeLines Limited ("TCPL") in respect to its Canadian Mainline ("TCPL Mainline"), the NEB changed the allowed capital structure, rather than the allowed ROE, to recognize changes in business risk (Reasons for Decision in RH-4-2001, June 2002 and in RH-2-2004 Phase II, June 2005).

In its RH-1-2008 cost of capital decision for TQM, the NEB followed the second approach, stating that "The freedom for a company to choose its optimal capital structure is consistent with the Board's philosophy of regulating pipeline companies on a goal-oriented basis. Exercise of that freedom does not, in the Board's view result in a wealth transfer, and is supported by the longstanding stand-alone principle" (page 81).

In my opinion, both approaches are valid ways of arriving at a fair return as long as the combination of capital structure and ROE for a particular pipeline reasonably compensates shareholders for the pipeline's business risk relative to that of its peers. The advantage of the second approach is that it is, in principle, compatible with the philosophy that the capital structure, within a reasonable range, is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital.

For Enbridge, the second approach has been adopted for the estimation of the fair return for 2008, 2009 and 2010. To implement this approach, I:

1. Evaluate the reasonableness of the capital structure requested by Enbridge;

2. Approximate the ROEs applicable to a benchmark pipeline; and

3. Determine whether the ROE appropriate for a benchmark pipeline needs to be adjusted given Enbridge's business risks and the proposed capital structure.

V. CAPITAL STRUCTURE

Enbridge is proposing a capital structure for toll-making purposes containing 50% debt and 50% common equity.

The following principles should be respected when establishing both the cost of capital generally and assessing a reasonable capital structure for Enbridge:

1. The Stand-Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity
4. Ability to Attract Capital on Reasonable Terms and Conditions
5. Comparability of Returns.

Each of these five principles is defined below. The five principles which apply to the determination of a reasonable capital structure include the three requirements (Principles 3 to 5) which govern a fair return as set out in Section IV above, reflecting the interdependence between capital structure and ROE.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by the shippers should be equivalent to that which would be faced if owning and operating Line 9 were Enbridge's only business, raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the pipeline should reflect neither subsidies given to, nor taken from, Enbridge Pipelines' other activities, such as the other two segments of the Enbridge System, or those of Enbridge Inc., the ultimate parent company. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a pipeline are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

A reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings. For the majority of regulated Canadian companies, a target debt rating in the A category is optimal from both a cost and market access perspective. Debt ratings in the A category assure that the regulated company would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. The critical nature of maintaining investment grade debt ratings arises from two factors: market access and cost. Even regulated issuers with BBB ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market.

For Enbridge, the fundamental business risks and small size would not likely permit it to achieve debt ratings in the A category on a stand alone basis, irrespective of the level of equity in the capital structure and allowed ROE.

While Enbridge is treated as a stand-alone entity for tollsetting purposes, Enbridge Pipelines raises debt on a company-wide basis and then allocates the debt to its individual pipelines such as Line 9. Enbridge is proposing to use Enbridge Pipelines' company-wide weighted average cost of long-term debt.[6] Enbridge Pipelines' debt is rated A(high) by DBRS and A- by S&P. Tollpayers on Line 9, therefore, receive the benefits of Enbridge Pipelines' ratings. In turn, Enbridge should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and ROE. It would be inequitable in principle for Line 9 tollpayers to receive the benefits of debt costs that reflect A(high)/A- debt ratings while Enbridge's common equity ratio (or equity thickness), in conjunction with its ROE, are inadequate to support those ratings, that is, would only support ratings below investment grade.

D. ABILITY TO ATTRACT CAPITAL ON REASONABLE TERMS AND CONDITIONS

Not only is the ability to attract capital on reasonable terms and conditions one component of the fair return standard, a higher cost of debt to the utility translates into a higher cost of debt to tollpayers. Maintaining investment grade debt ratings benefits all stakeholders.

To put the differences in cost of debt as among debt ratings in perspective, based on the indicated spreads for new issues which were published by RBC Capital Markets,[7] Enbridge Pipelines would have been able to raise new, company-wide 10-year debt on average at approximately 180 basis points over a similar term Government of Canada bond during 2008. Spreads on new 10-year issues for utilities with one debt rating in the BBB category (split-rated utilities) ranged from 200 basis points (Union Gas Limited rated A by DBRS and BBB+ by S&P) to 325 basis points (ENMAX Corporation, rated

[6] Under the terms of the FSA, the cost of debt was determined for Enbridge as the sum of the benchmark 10-year Government of Canada bond yield, a generic utility spread for 10-year term A rated corporate bonds and a fixed component of 0.65%. For 2008 and 2009, the embedded cost of debt for Enbridge includes the cost of a 10-year issue undertaken by Enbridge Pipelines of which $45 million was allocated to Line 9. This issue matures in 2009. For 2010 the cost of debt for Enbridge is the company-wide average cost of long-term debt.

[7] RBC stopped distributing the indicated spreads at the end of May 2009.

A(low) by DBRS and BBB+ by S&P). For companies with all debt ratings in the BBB category, the spreads ranged from 325 for FortisBC Inc. (rated BBB(high) by DBRS and Baa2 by Moody's) to 420 basis points for TransAlta Corporation (rated BBB by DBRS and S&P and Baa2 by Moody's).

The significant differentials (up to 250 basis points) between the potential costs of long-term debt of BBB rated companies and of Enbridge Pipelines provide a perspective on the potential magnitude of the cost of debt benefits which accrue to the Line 9 tollpayers. The determination of a reasonable capital structure for Enbridge needs to recognize the magnitude of the cost benefits conferred upon tollpayers through the proposed assignment of the company-wide weighted cost of long-term debt rather than an estimated stand-alone cost.

A pure application of the stand-alone principle would impute to Enbridge both the actual cost of debt that Enbridge would be able to obtain on its own and the capital structure that would be required by lenders to provide debt capital to Enbridge alone. Such an approach would ensure that the other operations of Enbridge Pipelines are not subsidizing Enbridge. However, given the small size of Enbridge relative to the total operations of Enbridge Pipelines, the latter's cost of debt would not be impacted in any measurable way by the financing requirements of Line 9. While the assignment of Enbridge Pipelines' weighted average cost of long-term debt to Enbridge is a departure from the pure application of the stand-alone principle, it is consistent with regulatory practice, where the actual cost of debt of the entity raising the debt is mirrored down to its various regulated operations. The approach also implicitly recognizes that each of Enbridge Pipelines' operations (and, by extension, tollpayers) benefit by way of a lower cost of debt from the size and diversity of the company's operations. Nevertheless, the combination of the capital structure adopted for toll-making purposes and ROE for Enbridge needs to recognize the significant cost benefits that tollpayers are receiving.

E. COMPARABILITY OF RETURNS

The combination of the adopted capital structure and return on capital should be comparable to the returns of comparable risk companies.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that Enbridge competes for capital with Enbridge Pipelines' other businesses, with other Canadian regulated companies, with regulated companies globally, as well as with unregulated companies, both within Canada and globally.

In its 2009 *World Energy Outlook*, the International Energy Agency estimated that between 2008 and 2030 close to $4.9 trillion in investment would be required for energy supply infrastructure in North America.[8] To compete successfully for required capital, Enbridge requires financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of its peers. The achievement of comparability requires explicit recognition of the financial parameters of the companies of comparable risk to Enbridge, including other regulated companies throughout North America.

VI. BUSINESS RISKS OF ENBRIDGE

A. CONCEPTUAL CONSIDERATIONS

Business risks have both short-term and longer-term aspects. The capital structure and fair rate of return on equity should reflect both short- and long-term risks. Long-term risks are important because pipeline assets are long-lived. The capital structure in particular needs to compensate for longer-term risks, as the financing of a pipeline is premised on the longer-term risks as perceived by investors when committing capital to the enterprise. Because regulated firms are generally regulated on the basis of annual

[8] Approximately $25.6 trillion world-wide.

revenue requirements, there has been a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, shipper resistance may forestall higher return awards when the risk materializes. Second, no regulator can bind his or her colleagues or successors and thus guarantee that investors will be compensated for longer-term risks when they are incurred in the future.

Business risk encompasses those market demand/competitive, supply and regulatory factors that expose the shareholders to the risk of underrecovery of the required return on, and/or the return of, their capital investment. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is typically designed around the inherent market and supply/physical risks.

B. TREND IN BUSINESS RISKS

In 1997 when Enbridge Pipelines applied for reversal of Line 9, the factors key to the business risk profile identified at the time, and thus to the proposed and approved capital structures and return on equity, were as follows:

1. The eight-year FSA was in place between Enbridge and the FSA Shippers (Imperial, NOVA Chemicals, Petro-Canada and Shell Canada). The FSA protected Enbridge from both variances between actual and forecast costs and throughput for a Primary Term of five years commencing when Line 9 began operating in reversed mode (east to west). While the FSA did not provide for similar protection during the Extended Term, subsequent letter agreements between Enbridge and the FSA Shippers extended the same level of protection until December 31, 2007.

2. The proposed reversal was in part based on the FSA Shippers' need to obtain competitively priced offshore (relative to Western Canadian sourced) crude to maintain their competitive position and enhance their viability.

3. The proposed reversal was based on the expectation that sufficient competitively priced offshore crude would be available so that Line 9 would experience high utilization beyond the Extended Term.[9] Specifically, the economic life of the reversed Line 9 was expected to be similar to that of the "Older System". Based on the depreciation rates proposed and approved, the economic life was expected to be 35 years.

4. There was an acknowledged risk that Line 9 could be underutilized in the early years of reversal because the reversed Line 9 would be accessing world supplies which had multiple outlets (versus an inland supply with limited outlets) and because the Enbridge market for the offshore supplies was limited and shippers on Line 9 had alternative sources of supply. It was as a result of these risks that Enbridge required the FSA to proceed with the reversal.

5. The FSA mitigated the short-term business risks of Enbridge, but did not eliminate the fundamental risks faced by the pipeline, since the FSA only covered eight years. Beyond the term of the FSA, Enbridge would be exposed to the risks of non-recovery of both return on and of capital, which were primarily a function of:

   (a) market risks arising from the nature of the Ontario refining market (limited outlets for off-shore supplies and access of refiners to alternative supplies); and

[9] National Energy Board, *Reasons for Decision, Interprovincial Pipe Line Ltd.*, *OH-2-97, December 1997*, pages 38 and 42.

(b) risks of supply interruption, which included operating risks of an unlooped line, the reliance on the availability of the Portland Harbor facilities and the connecting Portland to Montréal pipeline system, as well as the political risks associated with offshore supplies.

Looking forward as of January 1, 2008, Enbridge is exposed to a significant increase in the business risk as a result of the following:

1. The FSA expired on September 30, 2007. Enbridge no longer has the benefit of any contractual commitments by its shippers.

2. Only two of the four FSA Shippers remain: Imperial and NOVA Chemicals. Petro-Canada permanently closed its Oakville, Ontario refinery in 2005. In light of new sulphur specifications for producing gasoline, Petro-Canada opted to expand its Montréal facilities rather than incur the costs necessary to meet the environmental rules at what Petro-Canada referred to as the "small disadvantaged" Ontario refinery. Petro-Canada had accounted for approximately 25% of the Line 9 deliveries from the date of reversal in 1999 through 2004. Shell Canada has effectively stopped shipping on Line 9, receiving virtually all of its requirements from Western Canada. No other shippers are nominating volumes for transportation on Line 9.

3. Throughput on Line 9, which has a capacity of 240,000 barrels per day ("bbls/day"), has declined from an average of 215,200 bbls/day in 2000-2004 to 110,700 bbls/day in 2008. Deliveries in 2009 are estimated to decline further, to approximately 70,340 bbls/day.

4. Enbridge faces higher credit risk than at the time of the pipeline reversal. At the time of reversal, Enbridge had four investment grade FSA shippers, two with AA credit ratings (Imperial and Shell Canada), one with A credit ratings (Petro-Canada) and one with BBB credit ratings (NOVA Chemicals). Enbridge now has

only two shippers. While Imperial has continued to have very strong ratings (currently AAA by S&P and AA(high) by DBRS), NOVA Chemical's ratings dropped to B(high) by DBRS, BB- by Fitch, B3 by Moody's, and CCC+ by S&P. With the recent acquisition by International Petroleum Investment Company, which is wholly owned by the Government of the Emirate of Abu Dhabi, NOVA Chemical's ratings have generally improved (currently BBB(low) by DBRS, B+ by Fitch, B1 by Moody's and B- by S&P), however, NOVA Chemical's ratings remain, on average, well below investment grade.

5. According to the report by Muse, Stancil & Co., dated December 2009, and entitled "*Medium Term Prospects for Line 9 Westbound Service*" prepared on behalf of Enbridge (the "Muse Report"), from a pricing perspective, Western Canadian crude has become an increasingly more attractive option to Ontario refineries than North Sea crude. The report indicates that production of North Sea crude oil, which has been the primary source of offshore oil for Ontario refiners, has peaked and is expected to decline sharply subsequent to 2011. Further, the Muse Report indicates that although shippers can access alternative foreign crude supplies (e.g., Algeria) they incur higher transportation costs, which raises the total cost relative to shipments from Western Canada.

6. There have been major changes in the outlook for Western Canadian crude since the reversal of Line 9. In 1997, it was widely accepted that production of conventional light and medium from Western Canada that Ontario refineries were primarily designed to process was in decline. The long-term potential for oil sands production was recognized, but economics (world oil prices versus costs of extraction) had not favoured the wide-scale development of the resources. At that time oil sands were not even included in the estimates of world oil reserves. Natural Resources Canada was then estimating that total production from oil sands would reach 850 thousand bbls/day by 2020.

With the steady rise in world oil prices since 2001, and the improving technology for extraction and upgrading, oil sands production increased from approximately

428 thousand bbls/day in 1995 to 1.2 million bbls/day in 2008.[10] The Alberta Energy Resources Conservation Board ("ERCB") estimates that established reserves attributable to oil sands are l70 billion barrels; the remaining ultimate potential is approximately 315 billion barrels.[11] Currently the ERCB forecasts that production from the oil sands will reach approximately 2.7 million bbls/day by 2018; the Canadian Association of Petroleum Producers ("CAPP") forecasts production of 3.3 million bbls/day by 2025.[12]

7. Imperial has a significant equity stake in oil sands production, including Syncrude and Cold Lake operations, as well as the Kearl oil sands project formally announced in May 2009. With respect to the last, Imperial indicated that most of the initial production, expected in late 2012, would be going to its two Ontario refineries, with a smaller amount going to its Edmonton refinery.[13] Imperial has also announced that it is expanding production capability at Cold Lake. Increased availability and relatively attractive pricing of Western Canadian supply would favour Imperial moving additional crude from Western Canada in place of offshore supply, reducing the utilization of Line 9 below current levels.

8. Decreased utilization of Line 9 increases the tolls as the costs are allocated over smaller throughput. The higher tolls, in turn, reduce the attractiveness of shipping on Line 9. As tolls rise due to lower throughput, the economics of upgrading the Imperial refineries in Ontario to process additional Western Canadian oil sands crude improve.

9. Although NOVA Chemicals can potentially access at least a portion of its requirements from Western Canada, through the U.S. Gulf Coast, or both, Line 9

[10] Canadian Association of Petroleum Producers, *2006-2020 Crude Oil Forecast*, May 2006; Canadian Association of Petroleum Producers, *Crude Oil: Forecast, Markets and Pipeline Expansions*, June 2009, p.4.
[11] ERCB, *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*, June 2009.
[12] ERCB, *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*, June 2009 and Canadian Association of Petroleum Producers, *Crude Oil: Forecast, Markets and Pipeline Expansions*, June 2009.
[13] "Sitting on Kearl project announcement saved Imperial Oil more than $500 million", *Calgary Herald*, May 26, 2009.

is currently the more economic route for deliveries of condensate. However, if Imperial were to significantly reduce its throughput on Line 9, in favour of Western Canadian production, the increased tolls and transit time for delivery would shift the economics towards deliveries from the Gulf Coast. If Imperial were to cease utilization of Line 9 in westbound service, NOVA Chemical's volumes likely would not be sufficient to maintain the tolls at an economic level.

9. As a result of the changed dynamics in crude oil supply and pricing, Muse Stancil and Enbridge estimate that by 2016 the probability of Line 9 operating in westbound service is very low.

Enbridge's rate base includes the capital costs of the reversal project and of the subsequent maintenance of the line in westbound service. Enbridge is proposing to depreciate the remaining net book value related to the capital costs of the reversal project over ten years (commencing January 1, 2008), generally consistent with the Muse Report's estimate that, by 2016, Line 9 will likely no longer be operating in westbound service. The capital costs attributable to subsequent maintenance of Line 9, which could be used and useful should the line ultimately be re-reversed, will be depreciated using the same depreciation rates as Enbridge uses for its Older System.

While the proposed depreciation rates represent Enbridge's best estimates of the remaining depreciable life of Line 9, there remains a significant risk that the actual remaining service life in either direction will be shorter than currently anticipated. With respect to the reversal project capital costs, the estimated remaining depreciable life may be shorter than anticipated and the throughput necessary to recover the invested capital may not materialize. For the capital costs associated with the maintenance of Line 9 subsequent to reversal, shipper demand for re-reversal will dictate if and when Line 9 will be required to provide eastbound service.

In the current toll application, Enbridge is proposing a toll adjustment mechanism and deferral account for throughput, and deferral accounts for oil losses and regulatory costs.

The proposed toll adjustment mechanism and deferral accounts will mitigate short-term risk. However, the toll adjustment mechanism and deferral accounts, in particular the toll adjustment mechanism, do not mitigate the long-term fundamental risk. As compared to when Line 9 was initially reversed, the risk of failing to recover a compensatory return on and a return of the capital invested is significantly higher.

VII. CAPITAL STRUCTURES OF CANADIAN OIL PIPELINES

The capital structures, actual and allowed, of other liquids pipelines provide a relevant perspective on the reasonableness of Enbridge's proposed capital structure. First, oil pipelines which raise debt in the public markets have capital structures that have been "tested" by the capital markets. Second, the common equity ratios allowed for other oil pipelines, either through regulatory decisions or settlements, provide a measure of the level that is viewed as reasonable either by regulators or as a result of arms-length negotiations. In reviewing the actual capital structures, in conjunction with the corresponding debt ratings, consideration needs to be given to the terms and conditions of the debt issues which are rated. As regards both actual and approved equity ratios, differences in business risk as between Enbridge and other oil pipelines must be taken into account, as must the relationship between ROE and capital structure.

Table 2 below summarizes the actual and allowed common equity ratios for other Canadian oil pipelines.[14]

[14] Further detail on each pipeline is provided in Appendix B.

Table 2

Pipeline	Equity Ratio Approved for Regulatory Purposes	Regulator	Order	Actual Common Equity Ratio	Debt Ratings DBRS/S&P	Other
Enbridge Pipelines	N/A	N/A	N/A	46%	A(high)/A-	Actual common equity ratio is the 2006-2008 average calculated for the Mainline by DBRS
Enbridge Pipelines (N.W.) Inc.	55%	NEB	TO-4-99	N/A	N/A	Ship or Pay contracts; Negotiated; Multi-pipeline ROE
Express System	N/A [1/]	NEB (Canada) FERC (U.S.)	N/A	42%	A(low)/A-	Ship or Pay Contracts; Covenants protect debt holders
Milk River Pipeline	50%	NEB	TO-4-2001	N/A	N/A	ROE of 13% (vs. multi-pipeline ROEs of 9.6% and 9.5% for 2001 and 2002)
Plateau Pipe Line Ltd. (Western System)	50%	BCUC	P-3-01	N/A	N/A	BCUC benchmark ROE + 3%
Trans Mountain Pipeline ULC	45%	NEB	TO-06-2006	N/A	N/A	Negotiated Settlement; ROE of 10.75%
Trans-Northern Pipelines Inc.	50%-55%	NEB	TO-3-96	32% [2/]	A(low)/N/A	Negotiated Settlement; ROE based on multi-pipeline ROE plus 0.25%

[1/] Not cost of service based; no capital structure or ROE adopted since FERC approved a deemed common equity ratio of 55% and an ROE of 14.0% for the purpose of initial rates in 1996 (*Express Pipeline Partnership*, 76 FERC ¶ 61,245, September 11, 1996).

[2/] Expansion completed in early 2005 was debt-financed; equity ratio prior to expansion was 55%; DBRS expects the annual amortization of debt to return Trans-Northern's capital structure to an equity ratio range of 50-55% (to 50% by 2012).

Table 2 above demonstrates that the proposed common equity ratio of 50% is within the range of capital structures which have been maintained or adopted for regulatory purposes by other Canadian oil pipelines.[15] As discussed below, Enbridge faces higher business risk than the majority of the oil pipelines included in Table 2. For those that

[15] In addition to the pipelines covered in Table 2, the NEB has approved Enbridge Southern Lights GP's negotiated equity ratio of 30% with a corresponding ROE of 12%; it has also approved the negotiated 45% common equity ratio with an ROE equal to the multi-pipeline ROE plus 2.25% for Enbridge Pipelines' Line 4 Extension and Alberta Clipper.

face similar to higher business risk than Enbridge, the overall allowed returns incorporate ROEs which are materially higher than the benchmark allowed ROEs in their respective regulatory jurisdictions.

In comparison to both Enbridge Pipelines and Trans Mountain Pipeline ULC ("Trans Mountain"), Enbridge faces higher business risks, and thus a higher stand-alone cost of capital. Both have more diversified markets and shippers than Enbridge, as well as materially stronger competitive positions, particularly given the Muse Report's conclusion regarding the limited service life of Line 9 in westbound service. Both Enbridge Pipelines and Trans Mountain have a greater assurance of earning a reasonable ROE under the terms of their respective Incentive Toll Settlements than Enbridge.

In contrast to the Express System, which has contracts covering 82% of its capacity[16], Enbridge has no contractual commitments from its shippers. The Express System also has more diversified markets and shippers than Enbridge.[17]

Enbridge's business risks are higher than those of Trans-Northern Pipelines Inc. ("Trans-Northern"), as Trans-Northern has long-term firm service agreements covering a significant portion of its capacity, is the only refined products pipeline serving the Greater Toronto Area, and has access to refineries in both Ontario and Québec.[18]

Enbridge also faces higher business risks than Enbridge Pipelines (N.W.) Inc., which operates under a full cost of service ship-or-pay arrangement with Imperial and whose regulated common equity ratio is 55%.

The Milk River Pipeline is the only oil pipeline for which the NEB has rendered a decision on capital structure and ROE since the RH-2-94 decision in 1995. The Milk

[16] The Express System includes Express Pipeline Limited Partnership, Express Pipeline LLC and Platte Pipe Line Company. Contracts do not apply to Platte Pipe Line Company.

[17] The covenants covering certain of the Express System's debt issues (annual amortization and restrictions on distributions) provide for additional protection to debt holders and declining debt levels over time.

[18] On a business risk spectrum for mid-stream energy companies, Moody's considers product pipelines to be at the lower end of the spectrum, followed by interstate gas pipelines and then crude oil pipelines. (Moody's, *Rating Methodology: Midstream Energy Companies and Partnerships*, September 2007)

River Pipeline is a small system which delivers crude through connecting pipelines to refiners in Billings, Montana. In arriving at its decision on both capital structure and ROE for the Milk River Pipeline, the NEB determined that the pipeline "operates in a limited competitive environment and that it exercises some level of market power."[19]

Further, in arriving at its decision regarding the appropriate capital structure for the Milk River Pipeline, the Board noted the following,

> The business risks of the Milk River Pipeline may be somewhat higher than that of Trans Mountain. This is because the Milk River Pipeline is relatively smaller with more limited supply and markets. In the specific circumstances of this case, the Board considers a common equity ratio of 50% to be reasonable. Therefore, the Board deems the capital structure for the pipeline to be composed of 50% debt and 50% common equity.[20]

With regard to the allowed ROE, the Board stated the following,

> The business risk of the Milk River Pipeline which includes sales volatility, quality of its market and limited access to supply, is likely higher than the Group 1 pipelines subject to RH-2-94. The Board also considers the Milk River Pipeline to be exposed to higher financial risk than those of a benchmark pipeline referred to in the RH-2-94 decision. On this basis, the use of a higher ROE than that derived from using the RH-2-94 methodology is justifiable for purposes of setting tolls in this case. Thus, the Board finds that an ROE of 13% is reasonable in the current circumstances of the Milk River Pipeline.[21]

For purposes of comparison, the multi-pipeline ROEs for 2001 and 2002 were 9.61% and 9.53%, respectively. A 13.0% ROE represented a premium of close to 350 basis points above the multi-pipeline allowed ROE for the corresponding periods.

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[19] NEB, *Reasons for Decision, Murphy Oil Company Ltd. (now Plains Marketing Canada, L.P.), Concerning Tolls for the Milk River Pipeline, August 2001*, p. 13.
[20] *Ibid*., p. 12.
[21] *Ibid*., p. 13. The Milk River Pipeline had argued that an ROE higher than the multi-pipeline ROE was appropriate due to its small size, the fact that it served one relatively small and confined refinery area, increasing competition with the interconnection of the Express System to the Billings market, and the higher returns earned by the larger pipelines under multi-year toll settlements.

With respect to relative business risk, I would judge that the inherent business risks of the Milk River Pipeline and Enbridge are not dissimilar. The key differences in terms of stand-alone business risk are the short-term risk mitigation which will be provided for Enbridge by its proposed toll adjustment mechanism and deferral accounts and the relatively smaller size of the Milk River Pipeline.

With respect to Plateau Pipe Line Ltd. ("Plateau"), whose Western System accesses British Columbia crude, its circumstances are not dissimilar to those of Enbridge. It has one captive refinery customer, which has traditionally accounted for approximately 40% of its throughput. For the remainder of its capacity, Plateau faces competition from other sources of crude (Alberta, Alaskan North Slope) for deliveries to refineries in B.C. and the Puget Sound area and declining production rates of conventional crude in the northeast quadrant of B.C. Similar to Line 9, declining volumes on Plateau's Western System result in higher tolls, negatively impacting its competitiveness. The key differences between Plateau and Enbridge are the smaller size of Plateau and Plateau's lack of short-term risk mitigation through deferral accounts at the time the British Columbia Utilities Commission ("BCUC") approved Plateau's common equity ratio and ROE in 2001. Further, while there exists a potential for Line 9 to be re-reversed, Plateau does not have that option. On balance, I would judge Plateau to face somewhat higher business risks than Enbridge.

The June 2001 decision of the BCUC for Plateau's Western System adopted a 50% deemed common equity ratio and an ROE 300 basis points above its benchmark utility ROE.[22]

Based on the relative business risks of Enbridge, the proposed common equity ratio of 50% is reasonable.

[22] The BCUC's benchmark utility ROE is both conceptually and quantitatively similar to the NEB's multi-pipeline ROE.

VIII. CAPITAL STRUCTURE GUIDELINES OF DEBT RATING AGENCIES

Both Moody's and Standard & Poor's have issued quantitative guidelines for specific debt rating categories, including capital structure ratios (as well as other key credit metrics), which provide a broad perspective on the reasonableness of the 50% common equity ratio proposed by Enbridge.[23]

Since the majority of North American oil pipelines are structured as Master Limited Partnerships (MLPs), Moody's has designed a rating methodology for midstream energy companies, including oil pipelines, expressly targeted for the MLP structure. However, it also has a methodology for natural gas transmission companies which provides a perspective on the reasonableness of Enbridge's proposed 50% common equity ratio.[24]

Moody's has established debt/capital ratio guidelines of 35-45% (corresponding equity ratios of 55-65%) for an A rating and 45-60% (corresponding equity ratios of 40-55%) for a Baa rating for gas pipelines. Enbridge's proposed 50% equity ratio is below the lower end of the A range and in the middle of the Baa range for a gas pipeline. Although these guideline ranges are for gas, not crude oil, pipelines, Moody's considers that gas pipelines face lower business risk than crude oil pipelines.[25] While the actual ratings will take into account multiple factors, in isolation, they suggest Enbridge's proposed 50% equity ratio is conservative.

Standard and Poor's has guideline ranges for capital structure which encompass the full range of regulated company sectors, including oil pipelines.

[23] DBRS issued broad quantitative credit metric guidelines in 2002 which apply to electric and gas companies and which do not distinguish between rating categories.
[24] Moody's, *Rating Methodology: North American Diversified Natural Gas Transmission and Distribution Companies*, March 2007.
[25] Moody's, *Rating Methodology: Midstream Energy Companies and Partnerships*, September 2007.

S&P's current corporate rating methodology[26] assigns one of six business risk rating categories to each company that it rates including regulated companies. The lowest business risk category is "Excellent"; the highest business risk category is "Vulnerable." The category assigned takes into account the regulatory environment in which the utilities operate. Most regulated Canadian companies rated by S&P are in the "Excellent" category. The other business risk categories are "Strong", "Satisfactory", "Fair" and "Weak".

The business risk assessment is accompanied by a financial risk assessment. The financial risk assessment includes, but is not limited to, the consideration of three key quantitative credit metrics which include Total Debt/Total Capital. For each of the three metrics, S&P publishes a guideline range associated with six financial risk categories. The lowest financial risk category is "Minimal"; the highest financial risk category is "Highly Leveraged". The table below presents the guideline Total Debt/Capital ranges for each financial risk category. S&P notes that the guideline ranges are intended to represent the level of ranges that have been achieved historically and are expected to consistently continue.

Table 3

Financial Risk Category	Total Debt/Capital (%)
Minimal	Less than 25%
Modest	25-35
Intermediate	35-45
Significant	45-50
Aggressive	50-60
Highly leveraged	Over 60

Source: Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

The two matrices can be combined to determine the likely debt rating with a given business risk and financial risk profile. For example, a business risk profile ranking of

[26] Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

"Satisfactory" and a financial risk profile of "Intermediate" corresponds to a mid BBB debt rating. A business profile ranking of "Fair" and a financial risk profile of "Modest" corresponds to a debt rating of BBB-.

While S&P does not apply their guidelines mechanically, and the guidelines apply broadly across corporate sectors (not solely to regulated companies), the guidelines do provide direction as to ranges that are considered reasonable for ratings in the different rating categories. Given the business risk profiles assigned to the various Canadian utilities it rates, the highest business risk category that Enbridge would likely be assigned is "Satisfactory".[27] In isolation, for a "Satisfactory" business risk profile ranking, a debt ratio in the range of 35%-45% (equity ratio of 55%-65%) is indicated for a BBB rating.

The rating agency guidelines support the conclusion that Enbridge's proposed common equity ratio of 50% is conservative based on the level of stand-alone business risk to which it is exposed, but not unreasonable. As discussed further below, the ROE for Enbridge needs to be compatible with the proposed common equity ratio.

IX. RETURN ON EQUITY FOR ENBRIDGE

A. ALTERNATIVE APPROACHES

In this proceeding, Enbridge is applying for final tolls for 2008, 2009 and 2010. There are several potential alternatives for determining a reasonable ROE for Enbridge for all three years. These include: (1) separately estimating of the ROE for Enbridge "from first principles" for each of the three toll years;[28] (2) estimating the cost of equity for either 2008 or 2010 for Enbridge from "first principles" and estimating the ROE for the other two toll years using a formula approach; or (3) using a formula approach for Enbridge for all three years. Given the unique business risks of Enbridge, it is not possible to identify

[27] Both Pembina Pipeline Corp. and InterPipeline Fund, for example, are in the "Satisfactory" category.
[28] "From first principles" entails selection of proxy companies and application of the various cost of equity tests (e.g., risk premium, Capital Asset Pricing Model, discounted cash flow).

a sample of proxy companies whose business and financial risks precisely mirror those of Enbridge. Consequently, whichever of the alternatives is selected, the ROEs for Enbridge would be estimated by reference to the ROEs applicable to a "benchmark" pipeline.

In light of the relatively small size of Enbridge and the fact that separate ROEs are required for 2008, 2009, and 2010, I focused on the third alternative; namely, identifying a formula approach that could be applied for all three toll years, with the objective of simultaneously estimating fair and reasonable ROEs and achieving regulatory efficiency.

B. THE MULTI-PIPELINE ROE FORMULA

In RH-2-94, the NEB adopted a benchmark pipeline ROE of 12.25% at a long-term Government of Canada bond yield of 9.25%. At the same time, it adopted an automatic adjustment mechanism for the ROE which set subsequent years' benchmark pipeline ROEs. The formula adjusted the previous year's ROE by 75% of the change in the forecast long-term Government of Canada bond yield. The objectives of establishing a formula were to create regulatory efficiency (avoidance of annual ROE proceedings) and consistency across pipelines, that is, the ROEs would be set using a consistent set of financial parameters. The initial ROE of 12.25% which was established in RH-2-94 was not an unreasonable outcome for a benchmark pipeline at the time.

The NEB's formula operated for 15 years. In the intervening period, with the benefit of hindsight, it became increasingly clear that the required ROE did not track long-term Government of Canada bond yields in the manner indicated by the automatic adjustment mechanism.

Between 1995 and 2009, the forecast long-term Canada bond yield fell by 490 basis points; the corresponding benchmark multi-pipeline ROE fell by approximately 370 basis points, that is, by approximately 75% of the decline in forecast long-term Canada bond yields.

The decline in long-term Canada bond yields experienced during the past 15 years reflects in large part a sea change in the Canadian economy characterized by a shift from huge government deficits and indebtedness to an unbroken string of government surpluses (commencing in 1997) and a steady reduction in the relative (to the size of the economy) amount of debt outstanding.[29] With the vast improvement in the government's finances and the reduction in government debt outstanding relative to the size of the economy came the decline in long-term Canada bond yields. The secular decline in long-term Canada bond yields reflects three factors: a reduction in the expected rate of inflation over the longer-term, the waning of investors' fear that inflation would reignite to levels experienced in the 1980s decade, and a declining supply of long-term government debt relative to demand.

Of these three factors, only the decline in the expected rate of inflation over the longer-term would directly translate into a corresponding decline in the cost of equity. The fear that inflation would reignite had taken the form of a premium that bond investors required to "lock in" investment in long-term bonds with fixed coupon rates. Investors in equities, in contrast, are not similarly locked in and thus equity investors did not demand the same "lock in" premium. In contrast to the fixed rates on debt, corporate earnings, which ultimately determine the returns to equity investors, are better able to keep pace with the rate of inflation. The elimination of the "lock in" premium as inflationary fears waned lowered the risk associated with investment in long-term government bond yields. In the absence of a commensurate decline in the cost of equity, the result was an increase in the market equity risk premium.

With respect to the third factor, strong demand by institutions for a contracting supply of long-term government debt, particularly by those seeking to match the duration of their assets and liabilities, created an imbalance in the supply of and demand for these long-term government securities. The scarcity factor, in turn, lead to abnormally low long-

[29] The Federal government is anticipating budget deficits for fiscal years 2009/10-2012/13.

term government bond yields. A reduction in long-term government bond yields arising from a demand/supply imbalance has no bearing on the cost of equity.

Layered over the secular decline in long-term Canada bond yields have been periodic "flights to quality" throughout the period the formulas have been in effect. A "flight to quality" occurs when investors flee from risky securities to the safe haven of the safest securities, long-term government securities. A "flight to quality" puts downward pressure on the yields of default-free securities, for example, long-term government bond yields, and a corresponding increase in the cost of risky forms of capital. Since the introduction of automatic adjustment formulas, the capital markets have been characterized by multiple crises of varying proportions, including the "Asian Contagion" and ensuing Russian sovereign debt default in 1997-1998, the dot.com bust in 2000, the Enron bankruptcy in 2001, 9/11, the run-up to and the outbreak of the Iraq War in March 2003, and the global financial crisis dating from August 2007. The series of market crises and flights to quality during the period the formulas have been in operation has kept downward pressure on the level of long-term Canada bond yields, which in turn suppressed the level of the multi-pipeline ROEs.

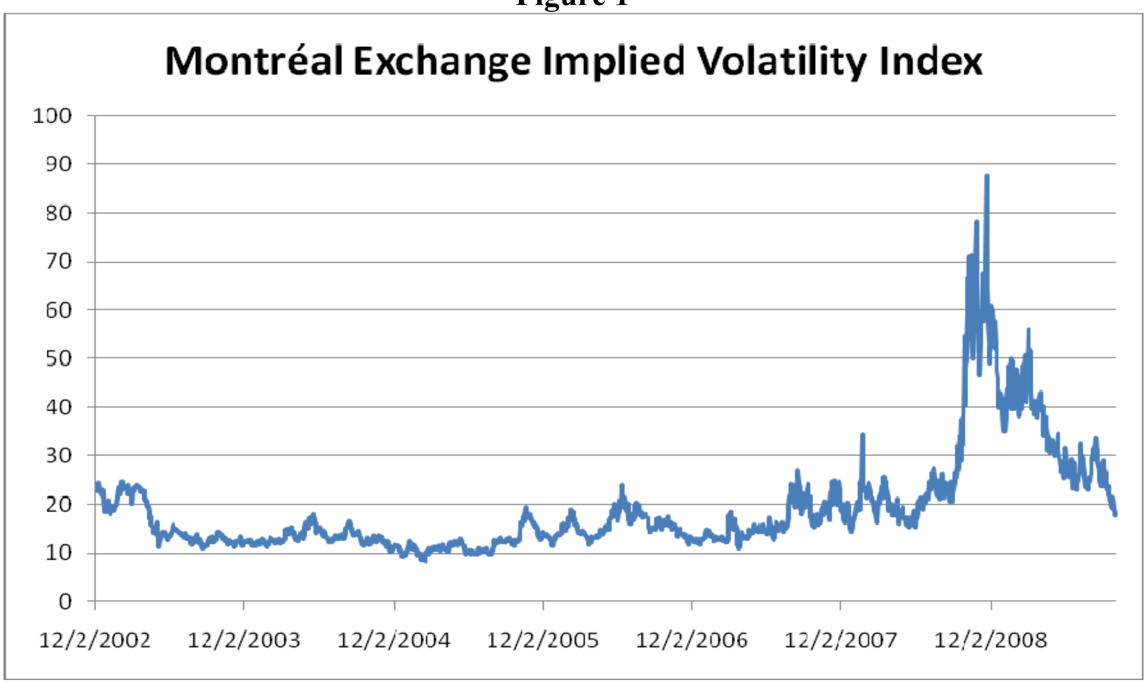
The November 2008 application of the multi-pipeline formula for 2009 clearly demonstrated that the existing formula also could produce incongruous results, that is, a decline in the multi-pipeline ROE at a time when the cost of capital was increasing. While the flight to quality had pushed both the actual and forecast yields on long-term government bonds lower during 2008, other capital market indicators were signalling a higher cost of capital. Between November 2007 and November 2008, the yield on long-term Enbridge Pipelines bonds (rated A(high) by DBRS and A- by S&P) had jumped over 150 basis points, from approximately 5.4% to 7.0%.[30] Over the same period, the yield on the S&P/TSX Composite rose by more than 1.5 percentage points as the equity market plunged. The higher dividend yield, similar to the increase in corporate debt yields, pointed to a higher cost of capital.

[30] Indicated spreads for a new Enbridge Pipelines' 30-year debt issue rose from approximately 120 basis points in November 2007 to a peak of 380 basis points in December 2008.

In addition to the increase in the S&P/TSX Composite dividend yield, the increase in the cost of equity and a widening of the equity risk premium were reflected in the significant increase in the volatility in the equity markets, as represented by the Implied Volatility Index ("MVX") introduced by the Montréal Exchange in 2002. The Montréal Exchange states that the "MVX is a good proxy of investor sentiment for the Canadian equity market: the higher the Index, the higher the risk of market turmoil. A rising Index therefore reflects the heightened fears of investors for the coming month."[31]

As shown in Figure 1 below, during much of 2002-2007, prior to the onset of the financial crisis, the MVX was relatively stable, trading within a range of 8 to 24, and averaging 15. During 2008, the MVX rose sharply, peaking at almost 90 in November 2008, its highest level since inception, and averaging close to 60 during the 4th quarter. To put this in perspective, the MVX never exceeded 25 prior to August 2007. The increase in the MVX signaled higher risk aversion and an increase in the equity risk premium.

Figure 1



Source: Montréal Exchange

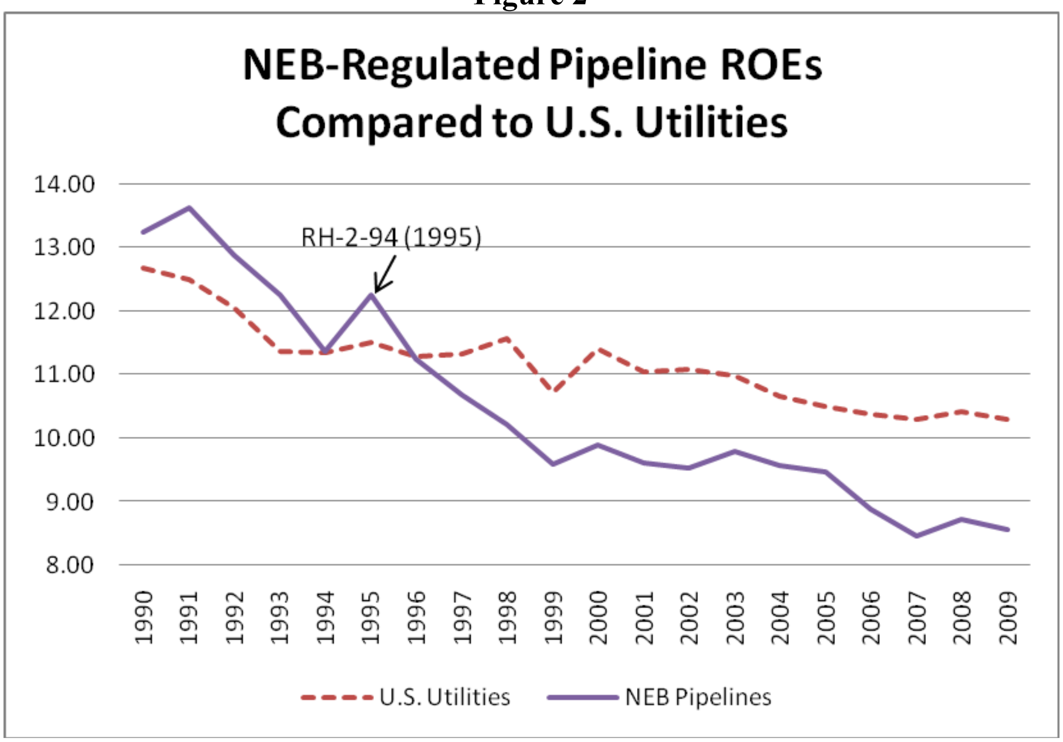
[31] www.m-x.ca/indicesmx_mvx_en.php

Despite broad-based market indicators to the contrary, the application of the multi-pipeline ROE formula, tied to government bond yields, resulted in a lower allowed ROE for 2009 than for 2008.

The extent to which the multi-pipeline formula ROEs diverged off course due to their dependence on the level of forecast long-term Canada bond yields can be assessed by a comparison of allowed returns for NEB-regulated pipelines to the returns adopted for U.S. gas and electric utilities during the corresponding year.

This comparison is germane given (1) the significant integration of the Canadian and U.S. capital markets, (2) the similarity in the business (or operating environments) for regulated companies in Canada and the U.S., and (3) the similarity in the regulatory models in the two countries.

Figure 2



Source: Schedule 1.

Figure 2 shows that the returns for the NEB-regulated pipelines and the returns adopted for gas and electric utilities in the U.S. were relatively comparable until approximately 1996. As the multi-pipeline formula continued to operate as initially constructed, a significant gap between the allowed ROEs emerged, a gap which has persisted through 2009. Between 1996 and 2009, the multi-pipeline ROEs have averaged close to 1.3 percentage points lower than the allowed returns of U.S. gas and electric utilities, whose allowed ROEs continued to be set in individual company proceedings. Over the same period (1996-September 2009), the average yield on long-term government bonds in the two countries was virtually identical (5.3% in both countries).

In the TQM decision, the NEB concluded that:

> there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM. (page 16)

The NEB also noted that

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008. (page 17)

On October 8, 2009, the NEB released its *Reasons for Decision, Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94)*, in which it expressed "the view that there is a doubt as to the ongoing correctness of the RH-2-94 Decision". The Board decided against replacing the RH-2-94 Decision with another multi-pipeline cost of capital decision, at least for now, and then held that "the RH-2-94 Decision will not continue to be in effect" (p. 2).

C. ADJUSTED BENCHMARK PIPELINE ROE FORMULA

In light of the changes in the capital markets since RH-2-94 and the NEB's recent decisions, I evaluated the potential for preserving the initial RH-2-94 benchmark pipeline ROE of 12.25% established in RH-2-94 as a point of departure for establishing the 2008, 2009, and 2010 ROEs for Enbridge, but by revising or adjusting the original formula to produce ROEs that more closely approximated the cost of equity for a benchmark pipeline over time.

Any ROE formula should be governed by three criteria:

1. Accuracy
2. Simplicity
3. Transparency.

The criterion of accuracy relates to the ability of the formula to reasonably quantify changes in the cost of equity over time. The results of any formula, no matter how complex, will only be an approximation of the cost of equity. Thus, the importance of accuracy should be weighed against the other two criteria. While the cost of equity and its determinants are complex, simplicity, both in terms of understanding the results and the application of the formula itself, is an important consideration to stakeholders, including tollpayers. Transparency simply means that the values of any variables that are used in the implementation of the formula are clearly defined, independently produced and easily verifiable.

An obvious potential substitute explanatory variable for long-term Government of Canada bond yields in an ROE formula is corporate bond yields.[32] Since both debt and equity holders have financial claims on the same cash flows of a corporation, all other things equal, it makes logical sense that changes in a firm's cost of equity will track changes in its cost of debt. Alternatively, since long-term corporate bond yields can be viewed as the combination of the long-term government bond yield and the spread between the two, an adjusted ROE formula could incorporate two separate variables: the forecast long-term Canada bond yield and the spread between long-term Canada bond yields and the yield on corporate bonds.

Corporate bond yield spreads are a widely used variable for explaining and estimating equity returns. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[33]

The relationship between the equity risk premium, long-term government bond yields and corporate bond yield spreads for regulated companies was tested two ways. First, the allowed ROEs adopted for U.S. utilities were used to test the sensitivity of the utility cost of equity to changes both in long-term government bond yields and utility bond yield spreads. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

Quarterly allowed ROEs from 1995 (the year the *Reasons for Decision* in RH-2-94 were released) through the third quarter of 2009 were regressed against long-term Treasury

[32] Changes in dividend yields are another alternative. The major drawbacks of using dividend yields in a formula are: (1) There is no "preset" index of comparable companies whose dividend yields could be tracked. Stakeholders would need to agree on a sample of companies which would serve as a proxy for a benchmark pipeline. (2) A change in dividend yield may signal a change in investor growth expectations rather than a change in the cost of equity.

[33] Examples include: Chen, N. F., R. Roll and S. A. Ross, 1986, "Economic Forces and the Stock Market", *Journal of Business*, 59, pages 383-403 and Harris, R.S. and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Summer 1992, *Financial Management*, pages 63-70.

bond yields and the spread between A rated utility and Treasury bond yields.[34] The results of the analysis indicate that the allowed ROEs increased or decreased by approximately 50 basis points for every one percentage point increase or decrease in the long-term government bond yields and increased or decreased by approximately 30 basis points for every one percentage point increase or decrease in utility bond yield spreads.[35]

An alternative analysis was performed using a benchmark sample of U.S. gas and electric utilities.[36] In this analysis, monthly estimates of the cost of equity for the sample were made over the period 1995 through the third quarter of 2009 using the discounted cash flow (DCF) model (see Schedule 2).[37] The monthly DCF cost of equity estimates were regressed against the corresponding month's government bond yield and spread between long-term A rated utility and government bond yields.

The regression indicates that, over the period of analysis, the cost of equity increases (decreases) by approximately 40 basis points for every one percentage point increase (decrease) in the long-term government bond yield and increases (decreases) by approximately 115 basis points for every one percentage point increase (decrease) in the utility/government bond yield spread (see Schedule 2).

The two analyses together support the conclusions that:

1. The sensitivity of the ROE to changes in long-term government bond yields is materially lower than the 75% factor in the original formula;

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[34] The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based. Excluding the spread as a second explanatory variable, the regression indicates that the allowed ROEs changed by approximately 40 basis points for every one percentage point change in long-term government bond yields.

[35] The regression is:

Allowed ROE = 7.88 + 0.47 * 30 Year Treasury Yield + 0.27 * Corporate Spread over Treasury

t-statistics (9.38) (3.26)

Adjusted $R^2 = 0.60$

[36] Criteria for selection of these utilities are described in Appendix C. U.S. utilities were relied upon due to the relatively small number of publicly-traded regulated companies in Canada and due to the changes in the composition of the Canadian utilities' operations over the past 15 years.

[37] The construction of the DCF estimates is described in Appendix C.

2. Although the two analyses produce different estimates of the sensitivity, the ROE is positively related to the change in utility/government bond yield spreads.

Based on the results of the two analyses, the original automatic adjustment formula should be adjusted as follows:

1. Reduce the relationship between the forecast long-term Government of Canada bond yields and the benchmark ROE from 75% to 50%; and

2. Add a second explanatory variable, corporate bond yield spreads, to the original formula with the same 50% sliding scale factor.

The resulting adjusted formula can be expressed as:

$$\begin{aligned}\text{Benchmark Pipeline ROE} &= 12.25\% + 50\% \text{ X (Change in Forecast GOC Bond Yield)} \\ &\quad + 50\% \text{ X (Change in Corporate Bond Yield Spread)}\end{aligned}$$

The adjusted formula is analogous to the automatic adjustment formula that was adopted by the Public Utilities Commission of the State of California in May 2008 to set the ROEs for the utilities under its jurisdiction. The California adjustment mechanism adjusts the ROE by 50% of the change in utility bond yields.[38]

Under the adjusted formula, the forecast long-term Government of Canada bond yield would be estimated in exactly the same manner as it was under the original ROE formula. The forecast long-term Canada bond yield is estimated using the November Consensus Economics, *Consensus Forecasts* of 10-year Government of Canada bond yields plus the

[38] Previously the Commission had conducted annual cost of equity reviews. Under the new approach, it will conduct cost of equity reviews every three years, with the automatic adjustment mechanism used to set ROEs during the interim years. The utility bond yields to be used in the adjustment mechanism for each utility will be governed by the specific utility's debt rating, that is, if the utility's debt is rated A, its ROE will be adjusted by 50% of the change in A rated utility bond yields. The operation of the mechanism is also subject to a trigger of 100 basis points. The ROEs will not be adjusted unless the relevant long-term utility bond yields change by more than 100 basis points).

October actual average daily spread between 30-year and 10-year Government of Canada bond yields. The relevant corporate bond yield spreads would be estimated using the actual difference between the yields on the long-term A rated Corporate Bond Index available from TSX Inc. and the yields on long-term Canada bonds prevailing at the time of the *Consensus Forecasts*.[39]

The adjusted benchmark pipeline formula results for each year 1996-2009 (compared to the multi-pipeline ROEs calculated as per the RH-2-94 decision) are set out on Schedule 3. The resulting average indicated pipeline ROE for 1996-2009 is 10.7%, versus 9.6% under the existing formula. To put this in perspective, the 10.7% average adjusted ROE compares to an average ROE adopted by regulators for U.S. gas distribution and electric utilities of 10.9% over the same period. The similarity in the average ROE produced by the adjusted formula and the average allowed ROEs for U.S. utilities is a reasonable outcome, given the similarity in the cost of capital environment in the two countries. As noted above, from 1996-September 2009, the average long-term Government of Canada bond yield and long-term Treasury bond yields were virtually identical, at 5.3%. Similarly, the average yield on long-term A rated utility bonds in the two countries was within 0.3% (6.9% in the U.S. versus 6.6% in Canada).

The indicated original benchmark pipeline ROE for 1995 and the adjusted benchmark pipeline formula ROEs for 2008, 2009 and 2010 are set out in Table 3 below with the corresponding long-term Canada bond forecasts and the A rated long-term corporate bond yield spreads.

[39] The index, the DEX Long Term Bond Index-Corporate A, formerly published by ScotiaCapital, is available by subscription from TSX Inc.

Table 4

Year	Forecast Long-term Canada Bond Yield	Long Term A Rated Corporate Bond Yield Spread	Benchmark Pipeline ROE
1995	9.25%	0.71%	12.25%
2008	4.55%	1.18%	10.13%
2009	4.35%	2.58%	10.73%
2010	4.19%	1.88%	10.30%

Source: Schedule 3.

The benchmark pipeline ROEs for 2008 and 2009 set out in Table 3 above reflect the application of the adjusted formula using (1) the same long-term Canada bond yield forecasts relied upon by the NEB to set the multi-pipeline ROE for the respective years and (2) the long term A rated corporate bond yield spreads prevailing at the time of the corresponding consensus forecasts.

The benchmark pipeline ROE for 2010 of 10.30% is based on a forecast long-term Canada bond yield forecast of 4.19% and a long-term A rated corporate bond yield spread of 1.88%. The long-term Canada bond yield for 2010 was estimated using the September 2009 Consensus Economics, *Consensus Forecasts* average of the 3- and 12-month forward forecasts of the 10-year Government of Canada bond yield of 3.7% plus the August 2009 average daily 30-year/10-year Canada bond yield spread of 0.49%. The long-term A rated corporate bond yield spread used to estimate the 2010 ROE represents the prevailing spread between the yields on the long-term Corporate A rated bond index and the long-term benchmark Government of Canada bond as of the end of September 2009.

The adjusted benchmark pipeline ROEs of 10.13% for 2008, 10.73% for 2009 and 10.30% for 2010 will be used as the benchmark pipeline ROEs for the purpose of establishing the corresponding ROEs warranted for Enbridge at its proposed common equity ratio of 50%.

D. EQUITY RISK PREMIUM FOR ENBRIDGE

The final step in the analysis is to determine whether, at the proposed capital structure containing 50% common equity, an adjustment to the benchmark pipeline ROEs is required for Enbridge.

The quantification of any adjustment requires two proxy samples of companies, one of relatively similar business risk to a benchmark Canadian pipeline and one of relatively similar business risk to Enbridge. The difference in the two samples' costs of equity, adjusted as required to recognize differences in financial risk between the two samples and Enbridge at its proposed 50% proposed common equity ratio, would provide an estimate of the adjustment to the benchmark pipeline ROE required by Enbridge.

The sample of publicly-traded A rated U.S. gas and electric utilities ("Benchmark Utility Sample") identified in Section IX.C above is reasonably comparable to a benchmark NEB-regulated pipeline. Each of the companies in the sample has been assigned an "Excellent" business profile score by S&P, the same score assigned to Enbridge Pipelines, NOVA Gas Transmission ("NGTL"), and TCPL. The sample average S&P and Moody's debt ratings are A and A3 respectively. The average S&P rating of Enbridge Pipelines, NGTL and TCPL is also A. NGTL and TCPL are rated A3 by Moody's.[40]

As a proxy for Enbridge, a sample of U.S. oil and gas transmission Master Limited Partnerships ("MLP sample") was selected.[41] The sample has an average business profile score of Satisfactory and ratings of BBB and Baa2 by S&P and Moody's respectively. Given the sample's average business risk profile of Satisfactory and debt ratings in the BBB/Baa category, it is a reasonable proxy for Enbridge.

[40] Enbridge Pipelines does not have a Moody's debt rating.

[41] The selection of the MLPs started with those in the Alerian MLP Index. All MLPs whose Global Industrial Classification System ("GICS") sub-sector code was not "Oil and Gas Storage and Transportation", whose primary business was not pipeline transmission, which were incorporated outside the U.S., which were an acquisition target, did not have *Value Line* coverage, and which either did not have a debt rating or whose debt ratings were below investment grade were eliminated.

The Capital Asset Pricing Model (CAPM) can be used to estimate the difference in the cost of equity. The Capital Asset Pricing Model holds that the equity investor requires a return on a security equal to:

$$R_F \quad + \quad \beta\,(R_M - R_F),$$

Where:

R_F	=	risk-free rate
β	=	investment risk beta
R_M	=	return on the market
$R_M - R_F$	=	market risk premium

The table below compares the investment risk betas of the benchmark utility sample and the MLP sample with their corresponding book value common equity ratios measured over the same period as the betas.

Table 5

INVESTMENT RISK BETAS					
Benchmark Utility Sample			**MLP Sample**		
Betas		**Common Equity Ratio (2002-2008)**	**Betas**		**Common Equity Ratio (2002-2008)**
"Raw" [1/]	Adjusted [2/]		"Raw"	Adjusted	
0.56	0.71	44%	0.77	0.85	49%

[1/] "Raw" betas represent the calculated correlation between the percentage change in the prices of a particular stock and the corresponding changes in the prices of the equity market index using weekly data for the period July 1, 2002-June 30, 2009.

[2/] The "raw" betas were adjusted using the following formula: ⅔ ("raw" beta) + ⅓ (market beta of 1.0). *Value Line,* Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

Source: Schedule 4.

A comparison of both the "raw" and adjusted investment risk betas indicates that, on average, the MLP sample betas are approximately 0.15-0.20 higher than the benchmark utility betas.

The investment risk beta, in principle, measures both business and financial risk, where the latter is represented by the capital structure. If the proposed common equity ratio of Enbridge were materially different from the capital structure maintained by the proxy MLP sample, the investment risk beta of the MLP sample would need to be decomposed into separate business and financial risk components to estimate the incremental ROE required by Enbridge at its proposed common equity ratio of 50%. In other words, the financial risk component of the MLP sample beta would have to be removed (that is, the beta would have to be "delevered") to derive a business risk-only beta for the sample. The business-risk only beta for the proxy sample would then need to be "re-levered" to derive an investment risk beta for Enbridge at its proposed equity ratio of 50%. Because the average common equity ratio of the MLP sample, at 49%, is virtually identical to Enbridge's proposed 50%, the decomposition of the MLP beta into separate business and financial risk components is not required. Given the similar capital structure of Enbridge and the proxy MLP sample, the 0.15-0.20 differential between the investment risk betas of the benchmark utility sample and the MLP sample can be used to estimate the incremental equity risk premium required for Enbridge relative to a benchmark pipeline.

The incremental equity risk premium required for Enbridge requires an estimate of the premium to which the differential in betas between the two samples would be applied.

As developed in Section IX.C above, the adjusted benchmark pipeline ROEs for 2008-2010 average 10.4%, reflecting a premium above the corresponding average forecast long-term Canada bond yield of six percentage points (10.4%-4.4%). An estimated incremental risk premium applicable to Enbridge can be derived by multiplying the average 6% benchmark pipeline risk premium by the ratios of the MLP betas to the benchmark sample betas. The resulting incremental equity risk premium for Enbridge is approximately 165 basis points (or, alternatively, a range of 150 to 175 basis points).[42]

[42] Based on average of raw and adjusted betas: ((0.81/.635) X 6%)-6% = 1.65%.

Enbridge, at an equity ratio of 50%, would incur a higher cost of debt financing than the cost at which Enbridge Pipelines could raise debt. At a minimum, the difference would be the difference between the cost to a BBB rated issuer and an A rated issuer. As noted earlier, Enbridge Pipelines is rated A(high) by DBRS and A- by S&P. The long-term average difference in the yield on long-term A and BBB rated utility debt has been approximately 35 basis points, or approximately 25 basis points on an after-tax basis at the 2008-2010 average corporate income tax rate of 30% (35 basis points X (1-.30) = 25 basis points). At a 50% debt/50% equity capital structure, the higher stand-alone cost of debt would translate into a 12.5 basis point higher after-tax weighted average stand-alone cost of capital for Enbridge (that is, 50% debt X the 0.25% incremental after-tax cost of debt).

With Enbridge Pipelines' lower cost of debt assigned to Enbridge, the ROE needs to be correspondingly higher (by 25 basis points) to equate to a stand-alone overall cost of capital for Enbridge compatible with its business risk. This consideration supports adjusting the range of the incremental equity risk premium for Enbridge of from 150-175 basis points to a range of 175 to 200 basis points relative to the benchmark pipeline ROE.

An incremental equity risk premium in the range of 175 to 200 percentage points compares to the incremental risk premiums of 300 and 350 basis points at 50% equity ratios adopted for, respectively, Plateau's Western System and the Milk River Pipeline by the BCUC and the NEB referenced in Section VII above. In that context, an incremental risk premium of 175 to 200 basis points for Enbridge is reasonable.

Adding the mid-point of the 175 to 200 basis point incremental equity risk premium range to each of the adjusted benchmark pipeline ROEs for 2008, 2009 and 2010, the indicated ROEs for Enbridge basis at a common equity ratio of 50% are:

2008	12.00%
2009	12.60%
2010	12.18%

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000, 2008
Gaz Metropolitain	1988

Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
MidAmerican Energy Company	2009
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007, 2009
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001

Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Nova Scotia Power	Calculation of ROE	2009
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

APPENDIX B

CANADIAN LIQUID PIPELINE OVERVIEWS

Pipeline: Enbridge Pipelines

Debt Ratings (DBRS/S&P):	A(high) / A-
Markets:	Eastern Canada and PADD II (U.S. Midwest)
Shippers:[1/]	62 Active Shippers
Contracts:	No long-term contracts; nominations made on monthly basis for following month
Competition:	Competitive risk from pipelines originating in WCSB (Express Pipelines, Trans Mountain and TCPL's Keystone when in service), and other pipelines delivering into PADD II markets
Regulation:	NEB Group 1: Operates under terms of the 2005 - 2009 Incentive Tolling Settlement (ITS). The ITS protects Older System from volume risk. Includes an allowance for pipeline integrity maintenance and recovery of non-routine factors (e.g. environmental).
Return on Equity (Allowed/Actual):	The ITS "has as its basis" the 2005 multi-pipeline ROE of 9.46%. Enbridge can earn above the multi-pipeline ROE through achieving cost efficiencies, power savings and meeting performance targets.
Capital Structure:	Regulated not specified; Mainline targets 45% equity
Debt Covenants:	N/A

1/ National Energy Board, *Pipeline Services Survey Results,* May 2009.

Pipeline: Enbridge Pipelines (N.W.)

Debt Ratings (DBRS/S&P):	NA
Markets:	Transports crude from Norman Wells, NWT to Alberta
Shippers:	Single major shipper: Imperial Oil rated AA(high) and AAA by DBRS and S&P
Contracts:	Ship or pay agreement through 2020 with Imperial
Competition:	None; feeder pipeline
Regulation:	NEB Group 1: Full cost of service
Return on Equity (Allowed/Actual):	Multi-pipeline Allowed ROE
Capital Structure:	55% Equity
Debt Covenants:	NA

Pipeline: Express System

Debt Ratings (DBRS/S&P):	A(low) / A-
Markets:	Crude oil from Alberta to U.S. PADD IV (U.S. Rocky Mountains) accounts for approximately 60% of volumes with remainder to PADD II (U.S. Midwest via Platte Pipeline)
Shippers:[1/]	20 Active shippers; 90% of committed volume shippers are investment grade (weighted average BBB)
Contracts:	Transportation Service Agreements (TSAs) cover over 80% of capacity into PADD IV; expire 2012 – 2015. Weighted average remaining term approxi-mately 4 years. No contracts on Platte into PADD II.
Competition:	Largest and most competitive pipeline into PADD IV; competes with Enbridge Pipelines/Lakehead in PADD II; will compete with Keystone Pipeline when in service
Regulation:	Canadian portion: NEB Group 2: Complaint based for uncommitted rates; Contract Rates in both Canada and U.S. can increase by maximum of 2% per year under TSAs U.S.: FERC: Producer Price Index for Finished Goods sets rate ceiling for uncommitted shipments
Return on Equity (Allowed/Actual):	NA/DBRS Reported ROE for 2006-June 2008 of 11%
Capital Structure:	40% Actual equity ratio as of 6/08
Debt Covenants:	Annual Amortization of certain debt issues; restricted payments test

[1/] National Energy Board, *Pipeline Services Survey Results,* May 2009.

Pipeline: Milk River Pipeline

Debt Ratings (DBRS/S&P):	NA (owned by Plains All American Pipeline)
Markets:	Crude oil to refineries in and around Billings, Montana (PADD IV)
Shippers:	Three Billings, Montana refineries account for over 80% of throughput.
Contracts:	NA
Competition:	Other US pipelines (Billings, Montana) and Express (intra-Alberta). NEB: "limited competitive environment".
Regulation:	NEB: Complaint based
Return on Equity (Allowed/Actual):	13% Allowed ROE set in 2001
Capital Structure:	50% Regulated Equity set in 2001
Debt Covenants:	N/A

Pipeline: Plateau Pipe Line Ltd. (Western System)

Debt Ratings (DBRS/S&P):	NA
Markets:	Crude oil to refineries in Prince George, BC (Husky) or via Kamloops onto Trans Mountain to Burnaby (Chevron Refinery) and Puget Sound (Shell Refinery, U.S. PADD V).
Shippers:	Husky, Chevron and Shell
Contracts:	None
Competition:	Sole pipeline to Husky Refinery in Prince George. Competition to Chevron (Burnaby) from Trans Mountain and to Puget Sound refineries (PADD V) from Trans Mountain and tanker.
Regulation:	BCUC: Complaint basis. Settlement through 2012 in 2008; fixed toll to Husky; cumulative toll ceiling for Kamloops shippers; Kamloops shippers agree to fund all costs subject to toll ceiling (expressed in total dollars of revenue)
Return on Equity (Allowed/Actual):	BCUC Benchmark ROE + 300bp in 2001
Capital Structure:	50% Regulated Equity set in 2001
Debt Covenants:	NA

Pipeline: Trans Mountain Pipeline (Mainline)

Debt Ratings (DBRS/S&P):	NA (DBRS rating of A (low) discontinued in 2005)
Markets:	Transports crude oil and refined products from Alberta and northeastern B.C. to the west coast, serving refineries in Vancouver (1) and Washington state (4); also has access to 19 refineries elsewhere in Washington, Oregon, California, Alaska, Hawaii, and to markets in Asia via pipeline interconnections and through its Westridge tanker loading facility in the Port of Vancouver
Shippers:[1/]	13 Active Shippers
Contracts:	No long-term contracts.
Competition:	Only pipeline serving own markets but competition in own markets from tanker (North Slope), rail and truck. Competition for volumes from other oil pipelines originating in WCSB (Enbridge, Express and Keystone when operative due to lower PADD V netbacks.
Regulation:	NEB Group 1: ITS for 2006-2010. Key elements include: (1) tolls based on 92.5% of design capacity; (2) annual escalation of operating costs; (3) rate base adjustments for expansions; (4) capacity incentives and penalties; (5) a minimum ROE of 7%; (6) certain flow-through costs (e.g., oil losses); and (7) toll trending.
Return on Equity (Allowed/Actual):	Allowed ROE of 10.75% under ITS
Capital Structure:	45% Regulated under ITS
Debt Covenants:	NA

[1/] National Energy Board, *Pipeline Services Survey Results,* May 2009.

Pipeline: Trans-Northern Pipelines Inc.

Debt Ratings (DBRS/S&P):	A(low) / N/A
Markets:	Serves markets primarily in Toronto, Ottawa and Montréal with refined products
Shippers:	Imperial Oil (1/3 owner), Petro-Canada (1/3 owner), Shell Canada (1/3 owner), Suncor and Ultramar.
Contracts:	50% of capacity accounted for by long-term (two-10-year terms on a ship-or-pay) contracts with Petro-Canada (40%) and Ultramar (10%) through 2025. Remaining capacity primarily un-contracted service with Imperial Oil and Shell Canada. Lower contract commitments for the second ten-year term beginning in 2015
Competition:	Ontario: Limited pipe competition from Sarnia Products Pipe Line and Sun-Canadian Pipe Line Company Limited. Québec: Competition from rail (Ultramar), truck and marine transport. TNPI is low cost operator
Regulation:	NEB Group 1: Has operated under settlements since 1996. Transportation revenue variances from revenue requirement applied to following year's revenue requirement; 50/50 sharing of operating cost savings
Return on Equity (Allowed/Actual):	Multi-pipeline Allowed ROE plus 0.25%
Capital Structure:	Regulated 50-55% equity. Actual 32% equity currently due to debt-financed expansion; expected to be 50% by 2012
Debt Covenants:	Scheduled semi-annual debt amortization

APPENDIX C

SELECTION OF BENCHMARK UTILITY SAMPLE AND CONSTRUCTION OF DCF COST OF EQUITY ESTIMATES

1. SELECTION OF BENCHMARK U.S. UTILITY SAMPLE

For purposes of estimating the relationship between the cost of equity, government bond yields and corporate bond yield spreads, a benchmark sample of U.S. utilities was selected, comprised of all electric utilities and gas distributors satisfying the following criteria:

a. Classified by *Value Line* as a gas distributor or an electric utility;

b. *Value Line* Safety Rank of “2” or better (on a scale of “1” to “5”);

c. Standard & Poor’s business risk profile of “Excellent”;

d. Standard & Poor’s debt rating of A- or higher;

e. Not presently being acquired; and,

f. Consistent history of analysts’ forecasts.

The 11 utilities that met these criteria are listed on Schedule 4.

2. CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the 11 utilities in the sample over the period 1995-20092Q. The monthly DCF cost for each utility was estimated as the sum of the utilities' I/B/E/S mean long-term earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. I/B/E/S is a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S mean earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly sample average DCFs were used to estimate the regression equation found on Schedule 2, page 2 of 2.

COMPARISON BETWEEN ALLOWED RETURNS
FOR NEB-REGULATED PIPELINES AND U.S. UTILITIES

	NEB-Regulated Pipelines			U.S. Utilities			U.S. Gas Utilities			U.S. Electric Utilities		
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.25	10.69	2.56	12.69	8.62	4.07	12.67	8.62	4.05	12.70	8.62	4.08
1991	13.63	9.72	3.91	12.51	8.09	4.43	12.46	8.09	4.38	12.55	8.09	4.47
1992	12.88	8.68	4.19	12.06	7.68	4.39	12.01	7.68	4.34	12.09	7.68	4.42
1993	12.25	7.86	4.39	11.37	6.58	4.79	11.35	6.58	4.77	11.41	6.58	4.83
1994	11.38	8.69	2.69	11.34	7.41	3.93	11.35	7.41	3.94	11.34	7.41	3.93
1995	12.25	8.41	3.84	11.51	6.81	4.70	11.43	6.81	4.62	11.55	6.81	4.74
1996	11.25	7.75	3.50	11.29	6.72	4.57	11.19	6.72	4.47	11.39	6.72	4.67
1997	10.67	6.66	4.01	11.34	6.57	4.77	11.29	6.57	4.72	11.40	6.57	4.83
1998	10.21	5.59	4.62	11.59	5.53	6.06	11.51	5.53	5.98	11.66	5.53	6.13
1999	9.58	5.72	3.86	10.74	5.91	4.83	10.66	5.91	4.75	10.77	5.91	4.86
2000	9.90	5.71	4.19	11.41	5.88	5.53	11.39	5.88	5.51	11.43	5.88	5.55
2001	9.61	5.77	3.84	11.05	5.47	5.58	10.95	5.47	5.48	11.09	5.47	5.62
2002	9.53	5.67	3.87	11.10	5.41	5.69	11.03	5.41	5.62	11.16	5.41	5.75
2003	9.79	5.31	4.48	10.98	5.03	5.95	10.99	5.03	5.96	10.97	5.03	5.94
2004	9.56	5.11	4.45	10.66	5.09	5.56	10.59	5.09	5.50	10.73	5.09	5.64
2005	9.46	4.38	5.08	10.50	4.52	5.98	10.46	4.52	5.94	10.54	4.52	6.02
2006	8.88	4.26	4.62	10.39	4.87	5.52	10.44	4.87	5.57	10.36	4.87	5.49
2007	8.46	4.30	4.16	10.30	4.80	5.51	10.24	4.80	5.44	10.36	4.80	5.56
2008	8.72	4.04	4.68	10.42	4.22	6.20	10.37	4.22	6.15	10.46	4.22	6.24
2009Q3	8.57	3.79	4.78	10.31	4.01	6.30	10.11	4.01	6.10	10.43	4.01	6.42
Means:												
1990-1993	**13.00**	**9.24**	**3.76**	**12.16**	**7.74**	**4.42**	**12.12**	**7.74**	**4.38**	**12.19**	**7.74**	**4.45**
1994-1997	**11.39**	**7.88**	**3.51**	**11.37**	**6.88**	**4.49**	**11.32**	**6.88**	**4.44**	**11.42**	**6.88**	**4.54**
1998-2009Q3	**9.36**	**4.97**	**4.39**	**10.79**	**5.06**	**5.73**	**10.73**	**5.06**	**5.67**	**10.83**	**5.16**	**5.71**

1/ 1990-1994 ROE is average allowed ROE for TransCanada PipeLines and Westcoast. 1995-2009 is formula ROE.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; Federal Reserve; U.S. Treasury.

DCF COST OF EQUITY STUDY FOR BENCHMARK U.S. UTILITY SAMPLE
(ANNUAL AVERAGES OF MONTHLY DATA)

	Expected Dividend Yield[1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Moodys' Spread
1995	6.1	3.9	10.1	6.8	1.1
1996	5.8	4.0	9.8	6.7	1.0
1997	5.6	4.2	9.7	6.6	1.0
1998	4.8	4.5	9.3	5.5	1.5
1999	5.2	4.9	10.0	5.9	1.7
2000	5.4	5.6	11.0	5.9	2.4
2001	5.0	6.4	11.4	5.5	2.3
2002	4.9	6.1	11.0	5.4	1.9
2003	4.7	5.3	10.1	5.0	1.5
2004	4.4	4.7	9.1	5.1	1.0
2005	4.1	4.7	8.8	4.5	1.1
2006	4.2	5.4	9.6	4.9	1.2
2007	4.0	5.3	9.3	4.8	1.3
2008	4.4	5.8	10.2	4.2	2.3
2009Q3	5.1	5.8	10.9	4.0	2.1
Under 5.0	**4.4**	**5.4**	**9.8**	**4.5**	**6.2**
5.0-5.99	**4.8**	**5.4**	**10.2**	**5.5**	**7.2**
6.0-6.99	**5.7**	**4.3**	**10.0**	**6.5**	**7.8**
7.0 and above	**6.2**	**4.0**	**10.2**	**7.3**	**8.2**
All	**4.9**	**5.1**	**10.0**	**5.4**	**7.0**

[1/] Dividend Yield is adjusted for I/B/E/S growth.

Source: Standard & Poor's Research Insight, I/B/E/S and www.federalreserve.gov

DCF COST OF EQUITY STUDY FOR BENCHMARK U.S. UTILITY SAMPLE
(ANNUAL AVERAGES OF MONTHLY DATA)
Regression Analysis Results

Return on Equity = 6.19 + 0.38 (30-Year Treasury Yield) + 1.13 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:	
Long-term Bond Yield =	8.58
Utility/government bond yield spread =	16.59
R^2 =	0.61

ADJUSTED BENCHMARK PIPELINE ROEs

	Forecast Long Canada Underlying NEB ROE [1/]	Change in Forecast Long Canada From 1995	NEB ROE per RH-2-94	Sept/Oct Corporate Yield Spread [1/]	Change in Yield Spread from 1995	50% of Change in Long Canadas
	(1)	(2)	(3)	(4)	(5)	(6)
1994						
1995	**9.25**		**12.25**	0.71		
1996	8.03	-1.22	11.25	0.42	-0.29	-0.61
1997	7.14	-2.11	10.67	0.27	-0.45	-1.06
1998	6.53	-2.72	10.21	0.28	-0.43	-1.36
1999	5.69	-3.56	9.58	0.99	0.27	-1.78
2000	6.12	-3.13	9.90	0.94	0.23	-1.57
2001	5.73	-3.52	9.61	1.56	0.84	-1.76
2002	5.63	-3.62	9.53	1.31	0.60	-1.81
2003	5.98	-3.27	9.79	1.32	0.61	-1.64
2004	5.68	-3.57	9.56	0.97	0.26	-1.79
2005	5.55	-3.70	9.46	0.98	0.26	-1.85
2006	4.78	-4.47	8.88	0.96	0.25	-2.24
2007	4.22	-5.03	8.46	1.07	0.36	-2.52
2008	4.55	-4.70	8.71	1.18	0.47	-2.35
2009	4.35	-4.90	8.57	2.58	1.87	-2.45
2010F	4.19	-5.06	8.37	1.88	1.17	-2.53
Average 1996-2009			**9.6**			

[1/] 2010 Long Canada based on September 2009 Consensus for 10-year Canada for September 2010 plus August 2009 spread. Corporate spread for 2010 is actual month-end September 2009 spread.
Source: NEB Decisions, Bank of Canada, PC Bond

DEBT RATINGS AND SAFETY RANKS FOR BENCHMARK UTILITY AND MLP SAMPLES

Benchmark Utility Sample	S&P Rating	S&P Business Profile	Moodys Rating	Value Line Safety Rank
AGL RESOURCES INC	A-	Excellent	Baa1	2
CONSOLIDATED EDISON INC	A-	Excellent	A2	1
DOMINION RESOURCES INC	A-	Excellent	Baa2	2
FPL GROUP INC	A	Excellent	A2	1
NEW JERSEY RESOURCES CORP	A	Excellent	A1	1
NORTHWEST NATURAL GAS CO	AA-	Excellent	A3	1
NSTAR	A+	Excellent	A2	1
PIEDMONT NATURAL GAS CO	A	Excellent	A3	2
SOUTHERN CO	A	Excellent	A3	1
VECTREN CORP	A-	Excellent	Baa1	2
WGL HOLDINGS INC	AA-	Excellent	A2	1
Average	**A**	**Excellent**	**A3**	**1.4**
Median	**A**	**Excellent**	**A3**	**1.0**
MLP Sample				
BUCKEYE PARTNERS LP	BBB	Satisfactory	Baa2	2
ENBRIDGE ENERGY PRTNRS LP	BBB	Strong	Baa2	2
ENERGY TRANSFER PARTNERS LP	BBB-	Satisfactory	Baa3	2
ENTERPRISE PRODS PRTNER LP	BBB-	Satisfactory	Baa3	3
KINDER MORGAN ENERGY LP	BBB	Satisfactory	Baa2	2
MAGELLAN MIDSTREAM PRTNRS LP	BBB	Satisfactory	Baa2	3
ONEOK PARTNERS LP	BBB	Satisfactory	Baa2	2
SUNOCO LOGISTICS PRTNRS LP	BBB	Satisfactory	Baa2	3
TC PIPELINES LP	A-	na	na	2
Average	**BBB**	**Satisfactory**	**Baa2**	**2.3**
Median	**BBB**	**Satisfactory**	**Baa2**	**2.0**

Sources: www.ratingsdirect.com, www.moodys1.com and *Value Line*

BETAS AND COMMON EQUITY RATIOS FOR BENCHMARK UTILITY AND MLP SAMPLES

Benchmark Utility Sample	Raw 7 Year Weekly Beta Ending June 30, 2009	Adjusted 7 Year Weekly Beta Ending June 30, 2009	Common Equity Ratio Average 2002-2008
AGL RESOURCES INC	0.67	0.78	40.3%
CONSOLIDATED EDISON INC	0.47	0.64	47.4%
DOMINION RESOURCES INC	0.61	0.74	37.1%
FPL GROUP INC	0.68	0.78	43.1%
NEW JERSEY RESOURCES CORP	0.58	0.72	47.8%
NORTHWEST NATURAL GAS CO	0.50	0.67	47.1%
NSTAR	0.52	0.68	35.3%
PIEDMONT NATURAL GAS CO	0.59	0.73	47.1%
SOUTHERN CO	0.36	0.57	40.6%
VECTREN CORP	0.65	0.76	41.5%
WGL HOLDINGS INC	0.59	0.72	51.9%
Average	**0.56**	**0.71**	**43.6%**
MLP Sample			
BUCKEYE PARTNERS LP	0.91	0.94	46.5%
ENBRIDGE ENERGY PRTNRS LP	0.82	0.88	45.2%
ENERGY TRANSFER PARTNERS LP	0.77	0.84	38.5%
ENTERPRISE PRODS PRTNER LP	0.81	0.87	47.3%
KINDER MORGAN ENERGY LP	0.52	0.68	42.4%
MAGELLAN MIDSTREAM PRTNRS LP	0.96	0.97	48.1%
ONEOK PARTNERS LP	0.67	0.78	41.7%
SUNOCO LOGISTICS PRTNRS LP	0.85	0.90	55.0%
TC PIPELINES LP	0.64	0.76	77.3%
Average	**0.77**	**0.85**	**49.1%**

Sources: www.yahoo.com and Standard and Poor's Research Insight

IN THE MATTER OF

TERASEN GAS INC. AND
TERASEN GAS (VANCOUVER ISLAND) INC.
APPLICATION TO DETERMINE THE APPROPRIATE
RETURN ON EQUITY AND CAPITAL STRUCTURE
AND TO REVIEW AND REVISE THE
AUTOMATIC ADJUSTMENT MECHANISM

DECISION

MARCH 2, 2006

Before:

R.H. Hobbs, Panel Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

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1.0 EXECUTIVE SUMMARY

On June 30, 2005, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") applied to the Commission to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism. TGI's return on equity and capital structure were established following a generic hearing by the Commission in 1994, at 350 basis points over the forecast long Canada bond yield and an equity component of 33 percent. The automatic adjustment mechanism was amended in 1999, with the result that when long Canada bond yields are forecast to be below 6 percent, the ROE rises and falls in step with the forecast long Canada bond yield. TGI has the lowest return on equity and smallest equity component of capital structure of any gas distribution company in Canada.

Up to 2002 TGVI's return on equity and capital structure were established by Special Direction issued by the Lieutenant Governor in Council to the Commission. Thereafter, under the Commission's negotiated settlement process, they were determined to be a 50 basis point premium over the return on equity of the benchmark low-risk utility (which the Commission determined to be TGI) and an equity component of 35 percent.

The Applicants seek the following returns on equity (based on the November 2006 consensus long Canada bond yield forecast of 4.79 percent) and equity component:

TGI	10.16%	38%
TGVI	10.91%	40%

The Commission Panel determines that both the comparable earnings standard and the capital attraction standard are equally relevant in establishing a fair return.

Accordingly, the Commission Panel gives weight to both the Equity Risk Premium and the Discounted Cash Flow approaches to establishing a fair rate of return. It is unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.

The Commission Panel concludes that the appropriate return on equity for a benchmark low-risk utility is 3.90 percent over the forecast long Canada bond yield. The Commission Panel determines that TGI will continue to be the benchmark low-risk utility. The Commission Panel also concludes that a revision to the automatic adjustment mechanism is appropriate, such that the return on equity will be adjusted by 75 percent of the change in forecast long Canada bond yields, effective January 1, 2006. Accordingly, the return on equity for

TGI for 2006 will be 8.80 percent and its equity component will be 35 percent. For TGVI the Commission Panel determines that a 70 basis point premium over the benchmark low-risk utility is appropriate for a return for 2006 of 9.50 percent, and an equity component of 40 percent.

2.0 INTRODUCTION AND BACKGROUND

2.1 Introduction

On June 30, 2005 Terasen Gas Inc. ("Terasen Gas" or "TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") collectively referred to as the "Companies" or the "Applicants" jointly filed an application (the "Application" with the British Columbia Utilities Commission ("BCUC" or the "Commission") to determine the appropriate return on equity ("ROE") and capital structure, and to review and revise the automatic adjustment mechanism ("AAM").

2.2 Overview

2.2.1 TGI

In 1994 the Commission was the first in Canada to hold a generic hearing into the appropriate rates of return on common equity and capital structure for utilities subject to its jurisdiction. It determined BC Gas Utility Ltd. ("BC Gas") (now Terasen Gas Inc.) to be the benchmark low-risk utility and established rates of return on common equity and capital structure for BC Gas, West Kootenay Power Ltd. (now FortisBC Inc.) and Pacific Northern Gas Ltd. ("PNG"). In addition, its Order No. G-35-94 established an AAM for calculating the allowed ROE on an annual basis.

In 1997 the Commission, by Order No. G-49-97, amended the AAM to correct for certain problems and to make it more consistent with the practices of other Canadian jurisdictions. In that Order the Commission directed that the range of forecast long Canada bond yields over which the AAM would apply would be 6.0 percent to 12.0 percent.

In November or December of each year from 1995 through 1998 the Commission issued letters to the Utilities subject to its jurisdiction establishing the ROE allowed for rate making purposes for each subsequent year based on calculations pursuant to the AAM. Centra Gas British Columbia's (now TGVI) ROE was set by Special Direction during that period.

In 1999, following an oral public hearing into the ROE for a low-risk benchmark utility and into the AAM, the Commission issued Order No. G-80-99, which directed that the AAM should continue to be employed, with certain exceptions:

- at forecast long Canada yields of 6.0 percent or below, the equity risk premium for a low-risk benchmark utility will be fixed at 350 basis points;
- at forecast long Canada yields of greater than 6.0 percent, the current contraction/expansion factor (i.e., the sliding scale) of 0.8 of the difference in forecast long Canada yields shall be retained and shall be driven off a low-risk benchmark utility ROE of 9.5 percent;
- to determine the forecast long Canada yield, the period over which the 10- to 30-year spread is to be measured shall be redefined as all the trading days in the October preceding the November Consensus forecast; and
- the Commission will canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

On November 1, 2000, BC Gas applied to the Commission to adjust the application of the automatic ROE adjustment formula to address the then current situation of yields on 10-year Government of Canada bonds exceeding the yields on 30-year Government of Canada bonds. The Commission reviewed the submissions of the various parties and decided not to vary the application of the ROE adjustment mechanism for 2001, as stated in Letter No. L-61-00.

In Letter No. L-62-01 the Commission established a written public hearing to review the yield spread between medium and long-term bonds in 2001 to consider whether amendments should be made to the mechanism for 2002. Following that written proceeding, the Commission determined by Order No. G-109-01 that the treatment of the yield spread between 30-year and 10-year bonds did not require adjustment. The Commission also determined that the ROE for the benchmark low-risk utility, expressed as a percentage, should be rounded to two decimal places prior to adding the utility-specific risk premium.

On July 22, 2004, TGI wrote to the Commission requesting the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review may be appropriate in the Fall of 2005 in time for implementation January 1, 2006.

By Application dated June 30, 2005, the Companies submit that since 1994, when the Commission introduced its ROE adjustment mechanism for setting rates of returns, which reflected the economic climate and circumstances of the day, much has changed and that in British Columbia, in Canada and in North America there is intense competition for capital.

The Applicants ask the Commission to move in accordance with these changed circumstances and recognize that it is not appropriate to subject investors in TGI to the lowest allowed return on equity in Canada.

Further the Applicants ask that the Commission recognize that British Columbia utilities must compete for capital with other Canadian utilities and with utilities in the U.S. and award returns on equity, and establish capital structures, that are appropriate in today's financial markets and reflect the business and financial risks of the utilities in British Columbia.

TGI requests that the Commission acknowledge changed circumstances by allowing it a common equity component of 38 percent in its capital structure, and a return on equity of 10.50 percent when long-term Canada bonds are forecast to yield 5.25 percent. TGVI requests that it be allowed a common equity component of 40 percent and be granted an additional 75 basis point increment over the allowed return on equity of TGI (i.e., 11.25 percent when the forecast yield on long-term Canada bonds is 5.25 percent).

Finally, the Applicants ask that the AAM be revised to make it comparable with other Canadian jurisdictions, both federal and provincial, which have established a sliding scale adjustment of 0.75:1 through its entire range of application.

On August 3, 2005, the Commission held a Procedural Conference, pursuant to Order No. G-69-05, to address the scope of the Commission's review of the Application, the steps and timetable associated with the regulatory review process and any other matters to assist the Commission to efficiently review the Application.

With input provided by Utilities and Intervenors at the Procedural Conference, the Commission defined the scope of the proceeding as follows:

1) The automatic ROE adjustment mechanism and all issues related thereto with respect to the establishment of the low-risk benchmark utility return used in the calculation of the appropriate ROE for utilities;

2) The capital structure for TGI and TGVI and utility-specific risk premium, if any, used in the calculation of the appropriate ROE for TGI and TGVI; and

3) The date the decision becomes effective.

A public hearing was held in Vancouver on November 14-18, 2005. Written Argument and Reply were received by January 5, 2006. Supplementary oral argument was heard by the Commission Panel on January 17, 2006.

2.2.2 TGVI

Under the terms of the Special Direction to the Commission issued under the Vancouver Island Natural Gas Pipeline Act ("VINGPA") by the Lieutenant Governor in Council through Order in Council 1510/95 the equity component of the capital structure and return on equity were set at 35 percent and 362.5 basis points over the long Canada bond yield respectively until December 31, 2002, after which time the Commission would set rates in accordance with the regulatory principles that are generally applied by it from time to time to gas distribution companies operating within British Columbia. In 2001 BC Gas Inc. (now Terasen Inc. or "TI") acquired Centra Gas British Columbia Inc. In 2003, in accordance with the negotiated settlement, the Commission approved by Order No. G-2-03 that TGVI's equity component of capital structure would be 35 percent and its ROE set at a premium of 50 points basis over the benchmark low-risk utility ROE.

2.2.3 The Law and the Jurisdiction of the Commission

Intervenors and Applicants cite four court decisions that they submit are relevant to the matters in this proceeding: *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C. et al.* [1960] S.C.R. 837 ("*B.C. Electric Railway*"), *Hemlock Valley Electrical Services Ltd. v. BCUC* (1992) 66 B.C.L.R. (2d) 1 (B.C.C.A.) ("*Hemlock Valley"), Bell Canada v. Canada* (CTRC) [1989] 1 S.C.R. 1722 ("*Bell Canada*"), and *Northwestern Utilities Ltd. v. Edmonton and Board of Public Utility Commissioners of Alberta* [1929] S.C.R. 186 *("Northwestern Utilities").*

In addition, the B.C. Old Age Pensioners' Organization et al. ("BCOAPO") reminds the Commission of its duties under the Utilities Commission Act ("Act", "UCA") in setting just and reasonable rates. These are:

1. a fair and reasonable charge for service of the nature and quality provided by the utility,
2. sufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, and
3. not unjust or unreasonable for any other reason [Utilities Commission Act ("UCA"), s. 59].

The Applicants submit that the *B.C. Electric Railway* and the *Hemlock Valley* cases make it clear that the obligation to allow a utility to earn a fair and reasonable return is absolute, and that a rate is unjust or unreasonable if it fails to yield a just and reasonable return on rate base (TGI/TGVI Submissions, p. 34, para. 115).

The BCOAPO cites *Bell Canada* and *Northwestern Utilities* and submits that the Commission must balance the interests of customers to a fair and reasonable charge for services with the interests of shareholders to fair and reasonable compensation. The BCOAPO submits that the Commission should take into account the rate increases that would result if the Application is approved (BCOAPO Submission, p. 7).

The Joint Industry Electrical Steering Committee ("JIESC") submits that all of the resources TGI and TGVI require, including the capital, must be obtained at the lowest possible cost and that the return must be equal to the returns available to investors on investments of comparable risk (JIESC Submission, p. 3; T7: 995).

The Commercial Energy Consumers Association of British Columbia ("CEC") submits that the obligation to allow a utility to earn a fair and reasonable return on rate base is not absolute, and that the Commission must balance the interests of customers and shareholders. The CEC further submits that if the obligation to allow a utility to earn a fair and reasonable return on rate base is absolute it would entitle new shareholders, who have paid a premium to departing shareholders of a regulated utility, to request a fair return on their investment, including any premium paid for the investment (CEC Submission, pp. 2-3).

<u>Commission Determinations</u>

The Commission's mandate is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act) [*UCA*, s.60 (1)(a) and (b)(i)].

The reasons of Locke J. and Martland J. in the *B.C. Electric Railway* case are ad idem on the matter of the need to consider both the costs of providing service and a fair return on invested capital used or prudently incurred to provide the service. First Locke J. said:

> "…I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant these matters as well as the undoubted fact

> that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered. Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable the company to earn such a return or such lesser return as it might decide to ask" (Exhibit A3-5, p. 848).

Martland J. said:

> "The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing an adequate and efficient service [as it is required to do by s. 5 of the Act (now s. 38)], without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive" (Exhibit A3-5, p. 856).

The submissions of the Applicants and the Intervenors in this proceeding are not ad idem regarding the appropriate consideration of the "balancing of interests". The Commission Panel finds the reasons of Locke J. and Martland J. instructive, and notes that they are accepted in the *Bell Canada* case. The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. As Martland J. said, "The rates to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on rate base." With the use of AAM, the determination of the cost of service and the determination of a fair return are now issues for separate processes.

As for the JIESC's lowest cost argument, the Commission Panel shares the view of the NEB, which recognized that "lowest possible" was not the appropriate test when it stated, at page 25 of its RH-2-94 Decision on generic cost of capital:

> "Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio possible."

2.3 The Applications

2.3.1 Benchmark low-risk utility

The Applicants seek revised capital structures and a return on equity appropriate to a benchmark low-risk utility.

TGI (then BC Gas Utility Ltd.) was deemed the benchmark utility in 1994 when the first generic ROE adjustment mechanism was established, and has continually been regarded as such by the Commission (Exhibit B-1, Tab 1, p. 2).

TGI's expert witness, Ms. McShane, describes a "benchmark low-risk utility" as a hypothetical construct. She considers that one objective measure of what constitutes a low-risk utility would be the utility's ability, on a stand-alone basis, to achieve debt ratings of A. In her view "The benchmark return is derived from data for utilities across industries (electric, gas distribution and gas pipeline), as well as from data for non-utilities. It is based on no specific utility and hence reflects no specific business or financial risk characteristics" (Exhibit B-1, Tab 2, p. 11).

2.3.2 Basis for filing the Applications

According to the Companies, the basis for the filing of the Applications is:

1) The AAM has resulted in TGI being allowed the lowest return on investment of any regulated energy utility in Canada.

2) The AAM has had unintended consequences when forecast long Canada bond yields are below 6 percent.

3) There have been significant changes in the Canadian economy and financial markets since 1994.

4) The business risk profile of TGI has changed since 1994, while its capital structure has been weakened by the elimination of preferred shares.

5) The capital structure and ROE should enable the companies to maintain adequate debt coverage ratios to avoid alarms from debt rating agencies.

6) The Commission should give weight to all three methods of determining the cost of equity capital namely the Equity Risk Premium, the Discounted Cash Flow and the Comparable Earnings tests (Exhibit B-1, pp. 2-3).

2.3.3 TGI

TGI states that in order to be designated the benchmark low-risk utility, it requires a common equity component in the capital structure of 38 percent as compared to the current 33 percent and a ROE of 10.5 percent when long Canada bonds are forecast to yield 5.25 percent (Exhibit B-1, Cover Letter, p. 3; TGI/TGVI Submissions, p. 1). Based on the consensus long Canada bond yield forecast of 4.79 percent the determination of the formula-based allowed ROE for 2006 is 8.29 percent (Exhibit B-25; B-26). The Applicants submit that any variance from a long-term Canada forecast bond yield of 5.25 percent should be accommodated through an adjustment in the ROE by 75 percent of the variance of long-term Canada bond forecast. On this basis, the 2006 ROE for TGI should be set at 10.16 percent [10.5%-(.75*(5.25-4.79))] (TGI/TGVI Submissions, p. 26; TGI/TGVI Reply Submissions, p. 46).

2.3.4 TGVI

TGVI seeks a common equity ratio of 40 percent and equity risk premium relative to the benchmark low-risk utility of 75 basis points. The current common equity component of TGVI is 35 percent and the premium is 50 basis points relative to the benchmark utility (Exhibit B-1, Tab 2, p. 18; Exhibit B-3, BCUC IR 40.1; Exhibit B-14A; TGI/TGVI Argument, pp. 32, 33). The determination of the formula-based 2006 allowed ROE for TGVI is 8.79 percent (Exhibit B-26). TGVI submits that its ROE should be set at 10.91 percent (i.e., 10.16 percent plus 75 basis points) (TGI/TGVI Submissions, p. 62; TGI/TGVI Reply Submissions, p. 46).

2.4 Acquisition of Terasen Inc. by Kinder Morgan, Inc.

The Applicants filed their application with the Commission on June 30, 2005. On August 1, 2005 Kinder Morgan, Inc. (“KMI”) and Terasen Inc., the sole shareholder of the Applicants, announced a definitive agreement whereby KMI would acquire all of the outstanding shares of TI for $35.91 per share. This amount is 2.7 times the book value of each TI share. The total purchase price, including the assumption of debt, is announced to be $6.9 billion. Following the announcement of the transaction Moody’s Investors Service announced that it would place TGI on credit watch with negative implications until it had investigated the implications of the transaction on TGI’s credit quality. Moody’s Investors Service downgraded TGI on December 19, 2005, stating that it had evaluated TGI’s credit on a stand-alone basis assuming that the regulatory ring-fencing imposed by the Commission would be effective in insulating TGI from the higher business and financial risk of its parent entities (Exhibit B-27, p. 1).

The Applicant's treasurer, Mr. Bryson commented on the transaction:

> "Well, I think that 2.7 book value was for the entire Terasen entity, which includes not just the gas utility business, but includes the pipeline business and the water business. You know, as we've indicated to investors over the past several years and demonstrated to investors over the last several years, we've got tremendous growth potential in our pipelines business…I think, you know, their public statements are clear that they saw the greatest potential in the pipelines business. When you add up the various growth opportunities that Terasen has in front of it, I mean, we're a $5-billion organization currently, with more that $5 billion of growth potential in that business segment alone" (T2: 123).

On August 17, 2005, KMI applied to the Commission under section 54 of the UCA for approval of the acquisition of the shares of TI. On November 10, 2005 the Commission approved the transaction, subject to certain conditions concerning "ring-fencing," independent governance and location of data. The ring-fencing provisions are designed to insulate TGI and TGVI from credit rating downgrades and related financial risks associated with any affiliates in the large Terasen/KMI corporate family. The conditions approved by the Commission are as follows:

1) Each Terasen Utility shall maintain, on a basis consistent with BCUC orders and accounting practices, a percentage of common equity to total capital that is at least as much as that determined by the Commission from time to time for ratemaking purposes.

2) No Terasen Utility will pay a common dividend without prior Commission approval if the result would reasonably be expected to violate the restriction in (1) above.

3) (a) No Terasen Utility will lend to, guarantee or financially support any affiliates of the Terasen Utilities, other than between TGI and TGS, or as otherwise accepted by the Commission.

   (b) TGI and TGS shall together maintain separate banking and cash management arrangements from other affiliates. TGVI shall establish separate banking and cash management arrangements from other affiliates once it has completed its proposed refinancing.

   (c) No Terasen Utility will enter into a tax sharing agreement with any affiliate of the Terasen Utility, unless the agreement has been approved by the Commission.

4) No Terasen Utility will enter into transactions with affiliates that are not in compliance with Commission guidelines, policies or directives regarding affiliate transactions, and no Terasen Utility will enter into transactions with affiliates on terms less favourable to the Terasen Utility than those available from third parties on an arms-length basis, unless otherwise approved by the Commission.

5) No Terasen Utility will engage in, provide financial support to or guarantee non-regulated businesses, unless otherwise approved by the Commission.

The intervenors filed the evidence of Dr. Booth on October 11, 2005. Dr. Booth summarizes his evidence with the following observation:

> "Kinder Morgan's (KMI) proposed takeover of Terasen Inc. is at an 11.8X expected 2006 EBITDA or 2.7X book value. This extreme valuation implies that the financial parameters applied to the Terasen companies are extremely generous and confirms my judgment that they should be reduced. The KMI takeover also calls into question the lack of ring fencing of Terasen Gas and the need for restrictions on inter affiliate cash management and transactions. Failing such ring fencing, in the face of the double leverage used by KMI to finance the transaction, there is a grave risk that Terasen Gas Inc.'s bond rating will suffer and ratepayers will be paying unfair and unreasonable debt costs" (Exhibit C2-6, p. 3).

Dr. Booth refers to a CIBC World Markets report dated August 19, 2005 that claims KMI plans a "double dip" financing structure, which would enable it to claim interest as an expense in both Canada and the U.S. which would result in lower taxes being paid by the new group (Exhibit C2-6, p. 83).

BCOAPO argues that the gas distribution companies were an integral reason that a premium was paid by KMI. This position is based on the expert evidence of Dr. Booth, who testified that because TGI represents 65 percent of the earnings of TI, "part of that 2.7 times clearly reflects the fact that they were happy with Terasen Gas" (BCOAPO Argument, p. 10).

The CEC argues that the KMI purchase at its high valuation is conclusive evidence in and of itself that the existing ROE and debt/equity structure is delivering a more than fair, just and reasonable return to departing shareholders and the new shareholders involved in the purchase (CEC Submission, p. 3).

The JIESC takes the position that when the allowed return equals the investors required return, the market to book ratio will be equal to one. The Intervenor cautions that if the ROE is set too generously, the market to book ratio will rise and the customers will pay more than is necessary to attract capital (JIESC Submission, p. 4).

The Companies in Reply Argument clarify that the KMI acquisition did not cause any change in the shareholding of either TGI or TGVI as the shares of both companies continue to be owned by TI. The Companies argue that the CEC was incorrect to suggest that TGI and TGVI are seeking to recover the premium over book value that KMI paid on the purchase of the shares of TI, and that there is no support for the Intervenors' argument that the new shareholder of TI was satisfied with the current ROE (TGI/TGVI Reply Submissions, pp. 6-7).

The Companies submit that the acquisition of TI by KMI should play no part in the Commission's determination of the requests for relief that was made in the Applications. The Companies argue that the Commission cannot infer that KMI was satisfied with the return that was in place (T7: 1031).

Commission Determinations

In considering the premium paid by KMI for the shares of TI, the Commission Panel is cognizant of the findings of the Alberta Energy Utility Board ("AEUB") in its Generic Cost of Capital Decision, July 2, 2004 (Exhibit A3-1, p. 28):

> "The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility. 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. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years."

The Commission Panel is aware of a number of strategic and fiscal factors that may have affected the price paid by KMI for the shares of TI. KMI can employ double leverage and can claim interest expenses in both the U.S. and Canada ("the double dip") to make the acquisition earnings accretive. TI's oil transportation business has significant growth opportunities. To protect the financial integrity of TI's gas distribution subsidiaries the Commission has initiated "ring-fencing" conditions. The Commission notes that Moody's Investors Service has announced that it is satisfied with the "ring-fencing" conditions imposed by the Commission and that the downgrading by Moody's of TGI was unrelated to the transaction. There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination.

3.0 AUTOMATIC ADJUSTMENT MECHANISM

3.1 Evidence and Argument

TGI has applied to change the contraction/expansion factor (or "sliding scale") component of the Commission's AAM such that the ROE will be adjusted by 75 percent of the change in forecast long Canada bond yields.

In 1994 the Commission implemented an adjustment mechanism for annually setting returns on equity, with revisions to the mechanism in the interim, including in 1999 as part of the Commission's 1999 ROE and Capital Structure Decision. The current mechanism increases the annual allowed return on equity by 80 percent of the change in forecast long Canada yields above 6.0 percent, and reduces the annual allowed return on equity by 100 percent of the change in forecast long Canada yields below 6.0 percent. Through its 1999 Decision the Commission also established that it would canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

Ms. McShane recommends that the Commission implement a symmetric 75 percent sliding scale, which she states would recognize that interest rates and the cost of equity do not rise and fall in tandem. She also submits that a 75 percent sliding scale would recognize the validity of the objectives of maintaining a stable financial profile and stable rates, and would put B.C. utilities on a similar footing as their Canadian peers (Exhibit B-1, Tab 2, p. 100). In support of her recommendation, Ms. McShane points to the results of her DCF-based equity risk premium test, which she concludes suggests that the utility cost of equity is less sensitive to changes in government bond yields than implied by the current sliding scale. In support, Ms. McShane also refers to her evidence of an average 75 percent ratio of Canadian utility dividend yields to long Canada bond yields in the period 1996-2004 as well as to her demonstration that a one percentage point change in the before-tax yield on a long-term Canada bond requires roughly a 70 basis points change in the utility return on equity to maintain a similar after-tax equity risk premium (Exhibit B-1, Tab 2, pp. 98-99).

Ms. McShane recommends that the formula should be reviewed if forecast long Canada yields fall below 4 percent or exceed 8 percent on the basis that long Canada yields outside of the range of 4.0-8.0 percent may indicate a materially altered relationship between long Canada yields and the utility cost of equity (Exhibit B-1, Tab 2, p. 100).

TGI submits that the current BCUC adjustment mechanism increasingly disadvantages B.C. utilities as long Canada bond yields decline, being the only such mechanism that provides for a one to one relationship between bond yields and allowed returns on equity (TGI/TGVI Submissions, p. 64). The Companies submit that the "penalization" of B.C. utilities can only be rectified by establishing a fair and reasonable return and implementing an adjustment formula with a symmetrical 75 percent sliding scale (TGI/TGVI Submissions, p. 64).

While Dr. Booth is not aware of any research to justify adjustment coefficients of either 0.75 or 0.80, and does not believe that risk premiums vary in a mechanical fashion with interest rates, he does support adjustment mechanisms as balancing the interests of shareholders and consumers and providing a viable compromise that avoids annual repetitive rate hearings. Dr. Booth judges that whether the adjustment coefficient is 0.75 or 0.80 is not material, but submits that that these coefficients are in the right range (Exhibit C2-6, pp. 67-68).

Dr. Booth recommends a sliding scale with an adjustment coefficient of 0.75. Dr. Booth has not specified any range in long Canada yields outside of which the formula should be reviewed since such cut-off points depend heavily on the economic situation that generates them, which cannot be specified ahead of time. Instead, Dr. Booth relies on the company, intervenors and Board staff to decide when a hearing is needed, based on their analysis of ongoing economic events (Exhibit C2-7, p. 85).

The JIESC accepts Dr. Booth's recommendation to change the adjustment mechanism after the benchmark return is reset so that for future changes being made pursuant to the adjustment mechanism, the return on equity is raised or lowered by 75 basis points for every 100 basis points change in long-term Canada yields (JIESC Submission, p. 40).

Other intervenors either made no submission on the sliding scale component of the AAM, or adopted the evidence of Dr. Booth and the submissions of the JIESC.

Commission Determinations

The Commission Panel notes that aside from recommended changes to the sliding scale component of the AAM, no other changes were recommended, such as to the method used to determine the forecast long Canada bond yield.

The Commission Panel is satisfied with the reasonableness of the proposed changes to the sliding scale recommended by TGI and supported by Intervenors. The Commission Panel approves a change to the adjustment mechanism such that the benchmark return on equity is raised or lowered by 75 percent of the change in the forecast long Canada bond yield.

The Commission Panel calculates that the result of this adjustment will be to increase the ROE for the benchmark low-risk utility for 2006 from 8.29 percent to 8.60 percent. The determination of the appropriate ROE is discussed in Section 6.

3.2 Review Process

Neither the Applicants nor the Intervenors make any recommendations concerning a periodic review of the process, or concerning events that should trigger such a review. In light of the AEUB finding in its 2004 Generic Cost of Capital Decision, the Commission Panel will adopt a review period of five years, while noting that any party continues to be free at any time to apply to the Commission to consider a review of the AAM. In addition, should the AAM result in a ROE for the benchmark low-risk utility of less than 8 percent or greater than 12 percent the Commission will canvass the views of the parties on whether the AAM should be reviewed.

4.0 RISK

4.1 Risk Defined

The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk.

Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:

> "…stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials" (Exhibit C2-6, p. 22, line 13).

Financial risk is measured through the debt equity ratio of a utility (Exhibit C2-6, p. 23).

Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards.

4.2 TGI

4.2.1 <u>TGI's Submission</u>

TGI submits that since the generic hearing and the introduction of the AAM in 1994 the competitive environment in which it operates has greatly changed, and that its business risks have increased significantly. The Companies identify nine components to the increase in the business risks of TGI and TGVI.

1) The operating cost advantage of natural gas versus other energy sources has declined; TGI provides Exhibit B-6 to illustrate a narrowing of the gap between gas and electricity for its residential customers in the Lower Mainland and Central interior of the province.

2) TGI's gas versus electricity price advantage is the lowest among Canadian gas distribution companies. Table 1 on page 7 of Exhibit B-1, Tab 1 shows gas to have a considerable price advantage over electricity in Alberta and Ontario.

3) Price competitive trends have led to declining captive rates for new customers. In addition to a greater proportion of new construction being multifamily dwelling, where TGI has experienced lower capture rates, TGI is experiencing reduced capture rates in single-family homes and estimates

its capture rate to have declined by 10 percent from the low 90 percent to the low 80 percent (Exhibit B-3, p. 64).

4) Alternative energy sources are more prevalent now than in the early 1990s. TGI cites ground source heat pumps in the residential sector, and industrial customers' ability to switch fuel types.

5) The annual use of natural gas by residential customers has declined through the 1990s and is forecast to continue to decline in the future; TGI states that residential use declined by 12.5 percent between 1997 and 2004, with a further 2 percent decline forecast to occur by 2009 (Exhibit B-1, Tab 1, p. 12-4). In Exhibit B-2, page 43, TGI notes that despite lower average consumption, its residential customers are paying more for use of natural gas.

In addition, TGI files data regarding its actual volumes sold and transported, which show a considerable decline:

Recorded Actual TGI Volumes – TJs

	Sales	**Transport**	**Total**
1995	124,856	56,426	181,282
1996	144,084	60,377	204,461
1997	135,866	58,305	194,171
1998	129,537	58,304	187,841
1999	136,150	63,382	199,532
2000	135,216	62,268	197,484
2001	120,553	58,806	179,359
2002	124,260	64,169	188,429
2003	113,391	62,415	175,806
2004	109,799	62,914	172,713

Notes
1. Includes Fort Nelson
2. Sales includes rates 1-7
3. Transport includes rates 22-27, excludes BC Hydro and TGVI Wheeling volumes (Exhibit B-12)

6) Changes in the gas supply environment have required TGI to become very proactive in the regional gas market and to develop strict controls on acceptable transactions and credit positions with external counterparties; TGI notes that it has proposed to extend its hedging program from 24 to 36 months. This necessitates larger credit lines to support mark to market losses on forward positions, and the need to contract only with creditable counterparties (Exhibit B-1, Tab 1, pp. 15-16).

7) TGI is limited in its ability to pass costs through because of the competitive pressure from other energy sources; this has required it to invest in software applications, which enable it to capture productivity gains (Exhibit B-3, p. 77).

8) Potential accounting changes for rate regulated enterprises, such as the elimination of accounting for regulatory deferral accounts, could introduce significant volatility into the earnings of such businesses and negatively impact compliance with excessive covenants and the ability to attract capital in the future (Exhibit B-1, Tab 1, p. 17).

9) TGI rejects the suggestion that deferral accounts eliminate or substantially reduce its business risk. Almost all utilities in North America now have energy cost deferral accounts and many have weather normalization accounts. This was not the case in 1994 when TGI was deemed to be the benchmark low-risk utility. TGI claims that, when compared to other regulated utilities, it is inappropriately designated as a "benchmark low-risk utility" (Exhibit B-1, Tab 1, pp. 17-18).

Ms. McShane, the Applicant's witness, submits that a 33 percent common equity ratio is too low for TGI to be considered equivalent to the benchmark low-risk utility. Her conclusion is based on factors that were similar to those cited by TGI: an increasingly competitive business environment in which TGI operates, and the fact that all major gas distributors have deferral accounts for the commodity cost of gas and many have rate stabilization or weather protection deferral accounts. In addition, Ms. McShane cites the relatively high concentration of TGI's demand in the industrial sector (40 percent) and the concentration of industrial load in a single industry, pulp and paper (Exhibit B-1, Tab 2, p. 15; T3: 326).

4.2.2 The Intervenors' Response

Dr. Booth disagrees with TGI's assessment of its business risk and submits that there is no significant increase in risk for TGI from higher natural gas costs. Dr. Booth notes that TGI continues to add customers and to grow its customer base, and that Terasen stated in its 2004 Annual Information Form (March 2005) that "Natural gas maintains a competitive advantage in terms of pricing when compared to alternative sources of energy in British Columbia." Dr. Booth also contends that if the risk of residential customers switching to alternative fuels was a significant risk to TGI it would be expected to be tracking and monitoring the situation, and the fact that it does not indicates that this is not considered to be a serious risk (Exhibit C2-6, pp. 32-34).

In Dr. Booth's view, "...utilities have the lowest business risk of just about any sector in the Canadian economy" and notes that the costs and revenues from gas distribution are very stable so that the underlying uncertainty in operating income is very low. Dr. Booth also notes that "...in the event of unanticipated risks, regulated utilities are the **only** group that can go back to their regulator and ask for "after the fact" rate relief" (Exhibit C2-6, p. 28, emphasis in the original).

Dr. Booth addressed TGI's business risk of not earning a return of capital, and offered the following solution:

> "The second and more risky situation is if the company can not rebalance to achieve its revenue requirement. This unlikely situation might occur if industrial and commercial users refuse to pay the higher rates resulting from the loss of residential load. In this case the recovery of the rate base is in question and Terasen runs the risk of stranded assets. However, if this risk is realistic, then the correct response is to change the depreciation rate so that the cost of potentially stranded assets is recovered from the existing users" (Exhibit C2-6, p. 33).

TGI counters this suggestion by citing an excerpt from a NEB decision re TransCanada Pipelines RH-2-2004:

> "…there is a potential that a company's tolls may not incorporate sufficiently high depreciation rates because competitive factors would prevent such rates from being charged. This potential, if significant, is appropriately compensated through the cost of capital.
>
> The assessment of cost of capital should assume that the depreciation rates reflect the best assessment of economic life of the pipeline. Consequently, resetting depreciation rates to reflect a new best estimate of economic life does not, by itself, reduce business risk from what it would be absent a change in the best estimate" (Exhibit B-5, Response to JIESC et al. 7.2c).

The parties do not address the issue further in their Submissions, in the Commission Panel's view, correctly. There is nothing before the Commission Panel to suggest either that the Applicants' depreciation rates do not reflect their best assessment of the economic life of their plant in service; or that their business risks can be eliminated by a change in depreciation rates.

4.2.3 Competitiveness of Natural Gas versus Electricity

With respect to the risks related to the competitive position of natural gas versus electricity, the JIESC notes that TGI had indicated that a year ago it had determined that there was a 95 percent probability that its residential natural gas rates would remain at or below British Columbia Hydro and Power Authority's ("BC Hydro") electricity rates (JIESC Submission, p. 10; T2: 97). However, the Companies submit that this statement refers to its information a year ago and that gas prices have increased since then, further decreasing its competitiveness (T3: 290). The JIESC also notes that TGI's estimate of the competitive electricity price was based on an internal estimate that assumed that electricity prices would increase at approximately one-half the rate of increase of BC Hydro's probable scenario in its 2004/05 Electricity Load forecast (Exhibit C2-15). The JIESC argues that Ms. McShane indicated that gas prices would be expected to moderate somewhat from the current high prices resulting from "the aftermath of the hurricanes" (T3: 330).

The JIESC files a slide from TGI's 2005 Annual Review that shows the five-year forward gas prices at the AECO Hub™ declining from approximately $13.50 Cdn/GJ in January 2006 to $7.00 Cdn/GJ in October 2010 (Exhibit C2-23). This trend is directionally consistent with the opinion of the Companies' witness Ms. McShane (T3: 329-330).

The JIESC also files a page from BC Hydro's December 2004 Electric load forecast for the period 2004/05 to 2024/25. The BC Hydro forecast states that its probable scenario assumes that electricity prices will increase at the rate of inflation (Exhibit C2-15), whereas TGI assumes a rate of increase for electricity prices that was one-half the rate of inflation (T2: 84).

The CEC argues that the risk associated with electric to gas competition has existed since the deregulation of natural gas pricing and as such it is a risk for which the utility has been compensated for a long time. In the view of the CEC, recent competitive pressures reflect supply tightening in the natural gas commodity sector and the realization of underlying risks, which have remained constant (CEC Submission, p. 19). The CEC also notes that Terasen did not use electricity price forecasts available from BC Hydro, nor had it studied the anticipated cost pressures on BC Hydro's electricity rates. The CEC also cites the testimony of Ms. McShane who agreed that a forecast of electric rate increases twice as high as that used by TGI would reduce the competitive pressure (CEC Submission, pp. 20-21).

The CEC disputes Terasen's claim that the customer attachment rate as a percentage of housing starts is approximately one-half of what it was in the mid-1990s (T2: 84). The CEC argues that if one accounts for the lag between the measurement of housing starts and customer attachments the relationship is more constant (CEC Submission, pp. 22-23). The CEC also argues that declining use rates are a normal result of higher efficiency equipment, more use of thermostat controls, increased insulation and trends towards multi-family dwellings. In the view of the CEC, these trends will create lower customer bills and improve the competitiveness of natural gas, even as electricity goes through a similar process of increasing efficiency. The CEC considers the trends concerning TGI to be evidence of "...the consolidation and firming of the core market towards its more fundamental needs..." for natural gas and not a factor increasing risk (CEC Submission, p. 24).

The Companies dispute the CEC argument that accounting for the timing difference between housing starts and customer attachments eliminates the decline, and replies that there has been a significant decline in customer additions and the number of customer additions as a proportion of housing starts since the early 1990s. The Companies also argue that while high efficiency furnaces and other advances may partly explain the decline in use per account, the fact remains that use per account and throughput are decreasing, which will lead to higher unit charges (TGI/TGVI Reply Submissions, p. 16; Exhibit B-12).

The Companies submit that the price competitiveness of natural gas has deteriorated since 1994 and 1999 and that, even though Exhibit C2-23 shows the forward price of natural gas declining over time from current levels, these forward prices continue to be higher than past prices and the Companies will face greater competition from electricity than in the past. The Companies argue that whether or not BC Hydro rates will increase at 1 percent or 2 percent per year is immaterial, when compared to the dramatic change in the relative prices in the price of natural gas and electricity and the volatility of gas prices (TGI/TGVI Reply Submissions, pp. 13-14). The Companies further argue that consumers' purchasing decisions are influenced not only by the absolute level of gas prices but also by their perception of price and volatility (TGI/TGVI Submissions, p. 10).

4.2.4 Deferral Accounts

The Applicants seek no change in their deferral accounts. TGI provides a listing and description of its deferral accounts plus a comparison to Union Gas Limited ("Union"), Enbridge Gas Distribution Inc. ("Enbridge"), Gaz Metro, and ATCO Gas (Exhibit B-3, Appendix 26.5).

TGI maintains two significant commodity deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). These commodity deferral accounts collect the difference between the actual incurred gas costs and recoveries from rates. TGI's non-commodity deferral accounts defer elements of gross margin and of costs. The most significant deferral account for TGI is the Revenue Stabilization Account Mechanism ("RSAM"). The Company describes its operation as follows:

> "The RSAM account deals with the Company's delivery margin and stabilizes the margins recovered from residential and commercial customers. The RSAM stabilizes delivery margin received from these customer classes on a use per customer basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years. Having an RSAM mechanism does not offer the company protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as industrial customers" (Exhibit B-3, Response to BCUC IR1 26.4.1).

TGI states that the approved 2005 delivery margin, including other operating revenues, totals $522.1 million, of which $100.5 million (21.2 percent) is subject to risk without deferral account protection. This amount comprises non-RSAM class customers of $82.4 million (15.8 percent), other operating revenues of $26.0 million (5 percent) and new customer additions of $2.1 million (0.4 percent) (Exhibit B-3, Response to BCUC IR1 26.7).

At December 31, 2004, the unrecovered balance on the RSAM Account was $59.5 million less related tax of $20.5 million (net of $39.0 million). TGI states that the balance on the account has accumulated over 11 years, with the balance being reduced in only two of those years (1996 and 1999).

Cost deferral accounts include the short-term and long-term interest rate deferral accounts which absorb interest rate fluctuations, and pension cost and insurance premiums deferral accounts, the latter two established as part of the 2004-2007 PBR settlement (Exhibit B-3, Appendix 1.5, p. 32). On the expense side, TGI states that of its 2005 test year expenses, O&M expenses of $152.1 million have no deferral protection, along with depreciation of $80.8 million (Exhibit B-5; JIESC IR No. 1, p. 15).

The JIESC argues that the Commission has allowed TGI "some of the most generous risk mitigation measures in the industry through extensive use of deferral accounts and through PBR regulation which provides an opportunity to earn returns above and beyond the allowed return" (JIESC Submission, pp. 11-13).

The CEC also submits that TGI "...has the most attractive deferral account treatment when considering that other jurisdictions are adopting some of these treatments....", and that deferral accounts contribute to providing the Company with very stable and predictable earnings. The CEC states that TGI's concern about deferral accounts is that these are ineffective in dealing with gas on electric competition, and argues that while deferral accounts provide TGI with very stable and predictable earnings, they are not intended to deal with gas on electric competition (CEC Submission, pp. 24-27). The CEC notes that only 18.1 percent of TGI's 2005 Test Year revenue is not covered through deferral accounts and consequently it has a highly predictable accounting income and a highly stable ability to earn its ROE (CEC Submission, pp.17-18; Exhibit B-5, Volume 5, Response to JIESC-BCOAPO-CEC IR1 7.1).

The JIESC notes that TGI earned its allowed return in every year since 1995, with the exception of 1998, which was due to employee severances paid out as a result of a major corporate restructuring to take advantage of PBR (JIESC Submission, p. 17; Exhibit B-5, JIESC-BCOAPO-CEC IR 7.1; T2: 79). The BCOAPO and the CEC echo this argument (BCOAPO Submission, p. 9; CEC Submission, p. 12).

The Companies agree with the CEC's submission that deferral accounts cannot deal with gas on electric competition and have not been proposed for such a purpose. The Companies also note that Dr. Booth indicated that the RSAM account should not affect the return on equity allowed (TGI/TGVI Reply Submissions, pp. 17-18).

The Companies acknowledge that PBR is beneficial to shareholders, but argue that it takes on additional risk by committing to O&M and capital targets, and by limiting its ability to seek relief from the Commission (T3: 286; TGI/TGVI Reply Submissions, p. 12).

4.2.5 The Companies' Response to Risk

The JIESC points to the TI annual report and testimony regarding the annual report to argue that:

> "The failure of Terasen to disclose any new material competitive risks in its annual report, where they must be disclosed or there will be legal penalties, should be proof that there are no new material risks the shareholders, or for that matter, there are no new material risks that the Commission should be concerned about" (JIESC Submission, p. 15).

In the JIESC's view there is no evidence that any prudently acquired asset of TGI will be economically stranded or that it will be unable to earn its allowed ROE in the future as it has in the past (JIESC Submission, p. 9).

The CEC also argues that if the risks to TGI were substantive, one would expect it to have invested in studying those risks and to have disclosed them in their Annual Report and Prospectuses where there is a legal obligation to disclose and be truthful. The CEC submits that the TI Annual Report and Prospectuses contain scant, if any, discussion of risks or disclosure of the potential to switch to alternative fuels. The CEC further argues that TGI appears not to have done any serious analysis to study or demonstrate the validity of the risk related to the price of gas relative to electricity, nor of consumer behaviour that would enable it to cope with competitive risks if they were significant (CEC Submission, pp. 32-36).

The CEC further submits that TGI has neglected to take actions that could mitigate the risks it perceives and has undertaken actions that exacerbate the problems it cites, including investment in expensive or uneconomic projects. The CEC also argues that TGI proceeded to acquire TGVI in spite of risks that were present before TGI purchased the utility. In summary, the CEC argues that TGI's response to its perceived risk is "tepid and weak" and consequently should not be granted any increased ROE or equity component at this time (CEC Submission, pp. 30-39).

The CEC dismisses TGI's claims with respect to various other risk adjustment factors, such as gas supply management challenges, cost management issues, regulatory accounting risks, and lack of growth. The CEC argues that TGI's claims with respect to these risks are either self-contradictory or unsupported by the evidence. The CEC submits that the underlying risk differs from the realized outcomes associated with risk and that the realization of a risk that has existed for some time does not change the risk of a company (CEC Submission, pp. 28-29).

The Companies contend that the risk disclosure in the TI Annual Report is appropriate in the context of Terasen Inc. and that an exhaustive discussion of TGI and TGVI's business risks comparable to the discussion in the hearing would give investors a distorted view of the overall business risk of Terasen Inc. "...given that its business risk remains relatively low compared to the broad equity market" (TGI/TGVI Reply Submissions, p. 11).

The Companies acknowledge that TGI is less risky than the "average" company (quotation marks in original) but argues that the evidence demonstrates that the relative risks of both TGI and TGVI have increased and that the risks faced by the Companies are greater than those faced by most other gas utilities in Canada (TGI/TGVI Reply Submissions, p. 10).

Commission Determinations

The Commission Panel finds that the vast majority of gas distribution companies in North America have some form of commodity deferral account, and that this protects both the utility from commodity risk and the customers from imprudent purchasing and from the utilities profiting from the purchase, transportation and storage of gas.

With the exception of the RSAM, which is discussed below, the Commission Panel finds that many of the other costs which are deferred by TGI are deferred as a result of PBR so that TGI is not penalized for underestimating or rewarded for overestimating a cost over which it has little or no control. Thus, the deferral is symmetrical. The Commission Panel finds the RSAM to be a unique account. It has two facets that the Commission Panel will consider separately.

The RSAM acts as a weather normalization account. In this regard, TGI is similar to a number of utilities in North America (including Gaz Metro and Newfoundland Power Inc., in Canada) that can defer the effects of temperature when and where it differs from a long-term norm used to set rates. The Commission Panel agrees with Dr. Booth and Ms. McShane that weather is a symmetrical risk, with equal odds of over and underachieving, that should not be taken into account when establishing the ROE for a benchmark low-risk utility.

The second function of the RSAM is to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. The Commission Panel considers this aspect of the RSAM to be a short-term business risk mitigant, which is not available to TGI's comparators. By "short-term", the Commission Panel means that it agrees with the Applicants that "the RSAM does not provide for recovery of the return on, or of, capital in the longer-term."

The issue is "whether the Applicants' business risk has increased," that is to say has the probability of TGI not earning a return on and of its capital increased since 1994. The evidence before the Commission Panel is clear: TGI has consistently achieved its allowed ROE in all years except one. The Commission Panel views the AAM, PBR and the RSAM as mechanisms that act to reduce the risk that TGI will not earn a return on its capital. As to earning a return of its capital, that is to say will TGI be able to recover its investment in property and plant in service through rates for service collected from its customers, the evidence is not as clear. In 1994, the evidence before this Commission was of a utility whose product enjoyed a broad competitive edge over electricity, whose long-term supply at reasonable prices seemed assured, and which was able to capture a significant share of new residential market. As Dr. Booth observed "So what happens is the growth allows more customers to lower the unit costs on the system, thereby making the distribution charge slightly lower making it slightly more competitive" (T5: 673). Today, TGI's competitive advantage has been significantly attenuated; its supply outlook has been altered by shippers moving B.C. gas east; and its capture rates in the new residential market have declined.

The Commission Panel can say with certainty that TGI's business risk has not declined in the period 1994-2005. It cannot say by how much its business risk increased, but it can say that although the probability of TGI not earning a return of its capital has increased, it continues to be very low.

The Commission Panel also shares the CEC's observation that if TGI genuinely perceives that it is facing increasing risk, it has a responsibility to undertake cost-effective actions that will mitigate risk. Such actions could include monitoring customer behaviour more closely in terms of such issues as fuel switching, disconnections, and energy efficiency and increasing efforts to offset the customer perception, cited by TGI, that natural gas is an expensive fuel.

4.3 TGVI

4.3.1 Evidence and Argument

In addition to the risks faced by TGI, the Companies set out the following risks peculiar to TGVI:

1) Building a new market on Vancouver Island;

   Ms. McShane describes TGVI as a relatively small greenfield utility, its market being built from the ground up over the past 15 years. TGVI's rates have been structured to compete with alternative energy sources and to induce potential customers to convert to natural gas. Ms. McShane summarizes that until 2003 TGVI's rates were set at a discount to competing fuels, too low to recover TGVI's cost of service and resulting in accumulations to the Revenue Deficiency Deferral Account ("RDDA"). Since 2003 TGVI's rates have been based on a cost of service model, incorporating a soft cap mechanism to maintain the competitiveness of rates in the residential and commercial sectors relative to electricity or oil alternatives (Exhibit B-1, Tab 2, pp. 18-19).

2) Continuing recovery of the RDDA:

   The Companies state that BC Hydro revenues from firm transportation of natural gas to the Island Cogeneration Project ("ICP"), in conjunction with royalty payments pursuant to the VINGPA, have allowed TGVI to reduce the RDDA to approximately \$60 million at December 2004 from its peak at \$88 million in 2002.

   The Companies argue that while TGVI and BC Hydro have signed a two-year transportation service agreement for the firm transportation of natural gas to ICP, there is no commitment from BC Hydro as to what will happen after the expiry of that contract. The Companies are concerned about the uncertainty of recovering roughly $16 million of the RDDA balance from BC Hydro in 2008 (TGI/TGVI Submissions, p. 19). The Companies summarize that under the approved 2006-2007 negotiated settlement agreement the RDDA balance is expected to be reduced by approximately $17.4 from a total of $52 million as of December 31, 2005 (TGI/TGVI Submissions, p. 20), or to roughly $34.6 million by the end of 2007 (Exhibit A3-6, Appendix A, Schedule 1, p. 14).

3) Planning for the elimination of Provincial royalty revenues in 2012 covering approximately 20 percent of the current cost of service;

   The Companies summarize that under VINGPA, TGVI receives royalty payments from the Provincial Government that reduce the cost of the gas commodity, which, in turn, improves the margin available to recover delivery costs. The Companies state that after the payments terminate at the end of 2011, TGVI's customers will be required to absorb the full commodity cost of gas. The Companies contend that the ability of TGVI to mitigate the impact of rising costs on customer rates will partly depend on its ability to add new customers, which hinges in large part on the competitiveness of TGVI's rates versus electricity rates. The Companies submit that given the intensely competitive market in which TGVI operates, there is a material risk that it will be unable to recover its full investment in utility assets (Exhibit B-1, Tab 2, p. 19).

   The Companies expect that the annual royalty payments will have grown to $60 million by 2012. The Companies submit that if TGVI has to apply for a $60 million revenue requirement increase in 2012 it would result in a rate increase of 35 to 40 percent across all customer classes, and that the current mechanism does not provide an adequate level of return to compensate for this risk (TGI/TGVI Submissions, p. 20).

4) High dependence on industrial load, in excess of 65 percent of throughput, two thirds of which is contracted on a year to year basis. The Companies note that 66 percent of TGVI's load and 38 percent of its margin is industrial, comprising of the ICP and seven pulp mills.

5) Security of supply risk since all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities. Ms. McShane describes TGVI as facing greater supply risks than the typical distribution utility, due to its dependence on a single pipeline system that traverses rugged terrain, with underwater and marine crossings (Exhibit B-1, Tab 2, p. 19).

6) Future repayment of $75 million non-interest-bearing senior government debt, currently sitting (sic) as a credit to rate base. The Companies point out that repayment will increase TGVI's rate base, contribute to higher cost of service and impact TGVI's competitive position (Exhibit B-1, Cover letter, p. 12).

The Applicants testify that, after the filing of the Application on June 20, 2005, BC Hydro has advised that it is evaluating the operation of the ICP as a peaking unit and purchasing transmission on an interruptible basis. As a consequence of this advice, TGVI states that it has elected not to proceed with its plan to sell a long-term bond issue to Canadian institutions and has chosen to refinance its debt in the amount of $350 million with short-term bank debt. This event has also caused its plan to obtain a rating for its long-term debt to be put on hold (T3: 316).

4.3.2 TGVI Deferral Accounts

A comparison of TGVI and TGI's deferral accounts to other Canadian gas utilities was provided (Exhibit B-3, Appendix 1.5). TGVI maintains a commodity deferral account called the Gas Cost Variance Account that captures the difference between actual and approved cost of gas. TGVI's most significant non-commodity deferral account is the RDDA, which has been operating for 15 years (Exhibit B-1, Tab 2, p. 18).

TGVI states that its approved 2005 delivery margin, including other operating revenues, is $118.0 million. Of this amount, $18.0 million of forecast revenue surplus is at risk without deferral account protection. The $18.0 million equates to 15.3 percent of TGVI's delivery margin.

TGVI states that the Special Direction provides for TGVI to have a RDDA funded by its shareholder. The RDDA shareholder funding mechanism has the result that in years when the revenues of TGVI are insufficient for it to earn its allowed return the shareholder funds the shortfall to cause the utility to have sufficient revenues to earn its return and vice versa (TGI/TGVI Submissions, pp. 19-20).

TGVI claims that its RDDA provides apparent protection against revenue risk, but it only does so through the shareholder funding the revenue deficiencies. Therefore, in reality, all revenues are at shareholder risk. It expects that in the longer term, if and when the RDDA balance is reduced to zero, a mechanism similar to TGI's RSAM will be put in place. The risk for TGVI is not so much delivery margins risk, but rather credit collection risk and whether its rates can ever be competitive, particularly after royalty revenues cease after 2011 (Exhibit B-3, p. 88).

Schedule 1 in TGVI's Negotiated Settlement Agreement for the 2006-2007 Revenue Requirements on line 28 (Exhibit A3-6), shows that in 2002 the RDDA reached a peak accumulated deficit of $88 million. From 2003 to 2004 TGVI has realized annual surpluses (Exhibit B-16, lines 41-42). These surpluses are expected to continue through to the end of 2007 resulting in a forecast RDDA balance of $34.7 million. Since 2003, TGVI's "soft-cap" rate design mechanism, together with revenues from the transportation agreement with BC Hydro, have allowed TGVI to incur annual surpluses. These surpluses allow TGVI to pay down the accumulated shareholder funded deficits and thus reduce the RDDA balance.

The RDDA allows TGVI to earn its allowed ROE before the VINGPA provision of $1.9 million and (Exhibit B-16, lines 1-10, col. a) which was a component in the Special Direction and agreed to in the VINGPA agreement in a negotiated arrangement (T3: 250). In a deficit year the RDDA revenue deficiency is added to earnings before revenue deficiency and in a surplus year the RDDA revenue surplus is subtracted from earnings before revenue deficiency in order to calculate net earnings (Exhibit B-16, lines 41-49, col. b).

The JIESC argues that some of the risks cited by TGVI, particularly the accumulation of a deficit that peaked at approximately $88 million in 2002, but has since been reduced approximately to $53 million in 2006 and $40 million in 2007, the planning for the elimination of the provincial royalty revenues in 2012, and the recent reductions in industrial gas throughput, could be a concern if they are taken out of context. The JIESC submits that while considering these concerns one should remember:

- That BC Hydro believes electricity rates will probably increase at the rate of inflation;
- That natural gas prices will probably decrease from current record levels; and
- That the combination of the two previous factors should make dealing with adverse factors much easier than anticipated by the Companies in the TGVI evidence (JIESC Submission, pp. 20-21).

The JIESC argues that the risks to TGVI are not new risks, but part of this project since its inception, and assumed by Terasen Inc. voluntarily when it purchased TGVI in March 2002. The JIESC stresses that in January 2003, TGVI voluntarily accepted a capital structure of 35 percent and a return on equity 50 basis points above the allowed return on equity of the benchmark utility as part of the 2003-2005 settlement agreement, and that there is no good reason to change either now. Further, the JIESC contends that the increased risks cited by TGVI are simply too remote to warrant any change in the capital structure or the return on equity of TGVI, particularly when upside opportunities are considered along with risk. The JIESC submits that both the allowed ROE and the capital structure should remain at present levels (JIESC Submission, p. 21). It also argues that to increase these components would make the utility less competitive and would affect recovery of the RDDA (JIESC Submission, p. 24).

The CEC argues that TGI proceeded with the acquisition of TGVI knowing the risks that TGVI faced and that the Commission cannot hope to deal with these risks through increasing equity and return on equity (CEC Submission, p. 38). The CEC contends that a utility that is now facing the realization of a risk for which it has been and continues to be compensated should not have access to even greater returns and even greater investment levels when the risks are being realized (CEC Submission, p. 29). The CEC also submits that TGI should work with the Provincial Government and its customers to develop long term plans for dealing with the pending materialization of risk that TGVI faces (CEC Submission, p. 45).

The Companies submit that the JIESC's statement that the TGVI risks are not new risks ignores the evidence that there has been a marked change in the risks of TGVI. While the JIESC says that risks are simply too remote, particularly when upside opportunities are considered along with risks, the Companies submit that the

Commission should not wait until an event occurs before recognizing the potential for that event to be a risk faced by a utility. The Companies contend that there is nothing remote about the loss of industrial demand, or high gas prices, or the loss of Royalty Revenues at the end of 2011 (TGI/TGVI Reply Submissions, p. 24).

The Companies argue that CEC's suggestion that TGI [sic] work with the Provincial Government and its customers recognizes that TGVI has significant risk that is materializing. The Companies submit that there is an obligation on the Commission to consider and determine those risks at this time; the Commission cannot avoid its obligations by referring TGVI's problems to the Provincial Government (TGI/TGVI Reply Submissions, pp. 30-31).

Commission Determinations

Section 3.1 of this decision deals directly with the TGI's business risks, and the Commission Panel attributes the same determinations to the change in the similar components ascribed to TGVI's business risk. The following determinations deal only with those TGVI risks summarized at the beginning of this section.

In assessing the business risk of TGVI, the Commission Panel is cognizant of the standard it set above when it defined business risk as the ability to earn a return on and of capital.

The Commission Panel finds that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada.

5.0 CAPITAL STRUCTURE

This section considers the appropriate capital structures for TGI and TGVI.

Dr. Booth believes the Commission should adjust for changes in business risk through the establishment of deferral accounts, as far as is practicable, then to alter the amount of debt financing; and then to alter the allowed ROE (Exhibit C2-6, p. 24). A review of deferral accounts is outside the scope of this proceeding. Therefore, determinations in this decision with respect to capital structure and returns on equity assume the deferral accounts are not changed. Further, the Commission Panel has used both capital structure and rates of return for establishing the appropriate financial profile for the Applicants. In this decision, the capital structure of TGI will be determined so as to equate TGI to the benchmark low-risk utility. In the case of TGVI, the reasonableness of the proposed capital structure and equity premium off of the return on equity for the benchmark low risk utility will be considered.

The capital structures of other B.C. utilities are outside the scope of this proceeding, although the approved capital structures of other B.C. utilities are considered relevant to the determination of an appropriate capital structure for TGI and TGVI.

5.1 TGI

The Applicants apply for a 38 percent common equity ratio for TGI.

5.1.1 Capital Structures of Other Canadian Gas Distribution Utilities

The table below provides the capital structures of other Canadian Gas Distribution Utilities:

Tab 2
SCHEDULE 5
PAGE 1 of 3

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date (1)	Order/ File Number (2)	Debt (3)	Preferred Stock (4)	Common Stock Equity (5)		Equity Return (6)	Forecast 30-Year Bond Yield (7)	
Electric Utilities									
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00	a/	9.50	5.55	
ATCO Electric									
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00		9.50	5.55	
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00		9.50	5.55	
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00		9.50	5.55	
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00		9.43	5.53	
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55		9.24	4.96	
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50		9.55	na	b/
Gas Distributors									
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00		9.50	5.55	
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61.91	3.09	35.00		9.57	5.81	
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50		9.69	5.80	c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00		9.80	5.65	d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00		9.03	5.53	
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61.50	3.50	35.00		9.62	5.68	
Gas Pipelines									
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Foothills Pipe Lines (Yukon) Ltd.	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00		9.46	5.55	
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00		9.46	5.55	

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1.95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions.

Source: Exhibit B-1, Tab 2, Schedule 5, p. 1

As indicated in the above table, all the other major gas distribution utilities have preferred shares in their capital structures. Since 1994 the allowed common equity of TGI has been 33 percent. In 1999 preferred shares were redeemed that accounted for 9.4 percent of the capital structure. The preferred shares of ATCO Gas, Enbridge, and Union are perpetual preferred shares. The Commission Panel accepts the evidence of TGI that it does not have a credit rating high enough to enable it to issue perpetual preferred shares (T3: 267). Therefore, the Commission Panel concludes that the preferred shares of ATCO Gas, Enbridge and Union need to be considered when comparing the capital structures of those utilities with TGI.

Ms. McShane and Dr. Booth reach similar conclusions regarding the relative risk of Canadian utilities.
Ms. McShane's view is that TGI's business risks are comparable to those of the major Alberta and Ontario distributors, and exceed those of electric transmission companies by a considerable margin (Exhibit B-1, Tab 2, p. 16). Dr. Booth is also of the view that electric transmission companies have a lower risk than TGI, and are judged to be the lowest risk regulated utilities in Canada. The AEUB has found that appropriate capital structure for electric transmission companies with no preferred shares is 33 percent.

McShane is of the view that TransCanada Pipelines and Nova Gas Transmission face no higher business risk than TGI. Dr. Booth is of the view that the gas transmission pipelines are the second lowest risk group. The allowed common equity ratio for TransCanada Pipelines, Mainline and Nova Gas Transmission are 36 percent and 35 percent respectively.

Dr. Booth then judged the local distribution companies, including both gas and electric as the next riskiest. Ms. McShane is of the view that TGI's business risks are comparable to those of the major Alberta and Ontario gas distributors. The allowed common equity ratios for the Ontario major gas distributors are in the range of 35 percent and the allowed common equity ratios for the Alberta gas distributors are higher at 38 percent.

In testimony, Dr. Booth indicated that TGI is riskier than ATCO Gas and Enbridge, roughly on par with Union, while being less risky than Gaz Metro (T5: 619-620). Dr. Booth views PNG and Gaz Metro as the riskiest regulated utilities in Canada (Exhibit C2-6, p. 36).

Although Dr. Booth recommends 35 percent for a typical local gas distribution company, he recommends 33 percent for TGI because of more comprehensive deferral accounts. The Commission Panel accepts that the TGI's earnings are less volatile than the earnings of Enbridge and Union, and such reduced volatility can be attributed, in part, to weather normalization. The Commission Panel also notes Dr. Booth's testimony that "I think they (sc Enbridge and Union) are probably happier not having weather normalization. Otherwise they would have proposed it" (T5: 639). The Applicant submits that the existence of the RSAM account is not a factor that should play a role in the determination of its allowed return on equity or its capital structure. Dr. Booth confirmed in his opening statement that weather risk should not affect the return on equity (TGI/TGVI Submissions, p. 14, para. 46 and 47).

5.1.2 Coverage Ratios and Credit Ratings

The pre-tax interest coverage ratios for the major gas distribution companies in Canada are set out below:

**PRE-TAX INTEREST COVERAGE RATIOS
FOR MAJOR CANADIAN UTILITIES**

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
Enbridge Gas Distribution	2.0	2.6	2.6	2.1	2.2	2.2	2.8	2.7	2.7
Gaz Metro	2.6	2.6	2.7	2.7	2.4	2.7	2.5	2.9	2.9
Pacific Northern Gas	2.1	2.7	2.6	2.3	2.3	2.3	2.3	2.5	2.3
Terasen Gas	1.8	2.0	2.3	2.3	2.3	1.9	1.8	2.0	2.0
Union Gas	2.2	2.3	2.4	2.0	1.8	2.0	1.9	2.1	2.1

Source DBRS (Exhibit B-1, Tab 2, Schedule 2)

TGI's interest coverage ratio for 2004 was 1.99 (Exhibit B-28)

TGI's Medium Term Note ratings for the years 1994, 1999 and 2004 are set out below:

Rating Agencies	**1994**	**1999**	**2004**
DBRS	A	A	A
Moody's	-	-	A2
CBRS/S&Ps	B++	A (low)	BBB (unsolicited)

Source: Exhibit B-3, Vol. 1, Appendix 2.1

On June 26, 2003, Standard & Poors downgraded TGI's rating from BBB+ to BBB. In the first quarter of 2004 TGI terminated Standard & Poors' engagement to provide credit ratings in order to manage costs. However, S&P elected to continue to publish unsolicited credit ratings on TGI debt. On December 19, 2005, Moody's lowered TGI's senior secured rating from A1 to A2 and TGI's senior unsecured rating from A2 to A3 (Exhibit B-27). Both Moody's and S&P are of the view that the low common equity component in the capital structure of TGI results in a weak financial profile. TGI submits that the December 2005 downgrading demonstrates the need for an increase to the common equity and return on equity for TGI (TGI/TGVI Reply Submissions, p. 27).

In its credit rating report on TGI dated June 22, 2004, DBRS makes the following comments on TGI from a credit analyst's (and thus bondholder's) perspective:

> "The company benefits from a supportive regulatory regime,"
>
> "The regulatory environment within which the company operates provides a relatively high degree of financial stability."
>
> "Key financial ratios are expected to continue to fluctuate within a narrow band in line with changes in working capital requirements, however, this does not pose any credit implications."
>
> "Terasen Gas has historically had the lowest allowed ROEs relative to all other gas distribution utilities in Canada. This has resulted in generally weaker financial ratios relative to its Canadian peers," and
>
> "The use of the taxes payable method of taxation (typical of rate-regulated utilities) has resulted in an unrecorded future income tax liability of $215.8 million as at December 2004. The recovery of this liability in future rates depends on regulation" (Exhibit B-5, Appendix 1.2).

The Commission Panel notes these comments by DBRS. First, the interest coverage ratios are stable and are unlikely to pose any credit implications in the future. Second, the lowest allowed returns, when combined with the lowest equity component relative to all other gas distribution utilities in Canada, have resulted in the lowest interest coverage ratios in Canada.

The Commission Panel accepts that if TGI is downgraded by one of the rating agencies to a non-investment credit that it could limit the number of investors willing to hold TGI debt securities. For that reason, investors may be reluctant to hold debt that is just one notch above BBB-. A credit rating below an S&P BBB- is considered "junk" (T3: 263-265). Therefore, TGI's credit rating would fall to non-investment grade (junk) status if S&P downgrades TGI by only two notches. In the December 19 Announcement, Moody's states:

> "TGI's rating considers the support provided by TGI's regulatory environment which limits TGI's exposure to commodity price and volume risks as well as pension funding costs and insurance costs by operation of numerous deferral mechanisms including Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (CCRA) and the Revenue Stabilization Adjustment Mechanism (RSAM). However, the rating also recognizes that the deemed equity and allowed ROE permitted by the regulator are among the lowest in Canada which contributes to TGI's weak financial metrics relative to its global peers" (Exhibit B-27).

The Applicants submit that TGI's hedging agreements require that collateral be posted if its rating falls to non-investment grade, which could trigger significant and sudden liquidity requirements. TGI's gas purchase agreements require that collateral be posted if the counterparty has reasonable grounds for insecurity, which could be triggered by a downgrade to non-investment grade (TGI/TGVI Submissions, p. 25, para. 85; T3: 265).

Dr. Booth believes that because bond rating agencies are concerned with accurately predicting the credit quality of a firm's debt, they take a conservative approach because of "asymmetry of risk" and sometimes over react (Exhibit C2-6, pp. 76-77). Moreover, Dr. Booth submits that S&P's decision to impose harsher credit standards has had no impact on spreads or presumably marketability of future debt issues, and notes that spreads have almost all declined since end of 2002 (Exhibit C2-6, p. 78). During the Oral Phase of Argument, TGI advised that there has been no determinable change in the market following the Moody's downgrade (T7: 984). The JIESC submits that the ratings are the agency's view of the utility, and that a more important view is the markets view as evidenced by the spreads.

The spreads of TGI with comparators including Enbridge and Union are provided at Exhibit C2-11, Exhibit C2-11 and BCUC IR No. 1, 32.1.1.2. TGI's 30-year bonds trade at spreads that are approximately 15-20 basis points higher than Enbridge and at spreads that are similar to Union's. In Reply Argument, TGI submits that TGI bonds trade at approximately 30 basis points higher than Enbridge; however, the trade spreads indicated on BCUC IR No. 1, 32.1.1.2 are 20 basis points and the estimated spreads for a new 30 year issue are approximately 30 basis points. TGI then submits that the "30 basis point spread" reflects a "particularly accommodating point in the interest cycle for TGI bonds" (TGI/TGVI Reply Submissions, p. 20).

Dr. Booth's view is that the S&P and the Moody's ratings for Terasen are out of line with what the market feels is the correct rating. During the Oral Phase of Argument, the JIESC also notes that both the Moody's and DBRS ratings are "A" ratings (T7: 978).

The Commission Panel also notes the submissions of TGI that from the perspective of independent parties, who can see there has been a change, the downgrades suggest the business risks and the financial risks of TGI have increased (T7: 980).

5.1.3 Access to Capital Markets and Financing Flexibility

The JIESC observes that TGI was able to raise 30 year debt in 2005 on reasonable terms. The Applicant's Treasurer Mr. Bryson states:

> "I think the point that I want to leave on this is that obviously one of the key standards that a fair return on equity and capital structure has to meet is the ability to raise financing even in adverse conditions. And I think that was acknowledged by this Commission in the 1999 ROE decision. And what I'd like to submit is that the ability to issue 30-year bonds once every five or ten years does not provide evidence that that test is being met" (T2: 154).

Mr. Bryson states that in 2005 at least seven BBB rated companies were able to issue 30 year debt (T2: 127).

The Commission Panel accepts the need for a utility to be able to access capital markets under most circumstances at reasonable rates.

Commission Determinations

The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities.

While the Commission Panel accepts the submissions of the JIESC that since utilities have the lowest business risk of just about any sector they should have the highest debt ratios, it nevertheless concludes that an increase to the capital structure of TGI is supported by post-1994 changes to the capital structure of TGI and by comparisons to the approved capital structures of comparable risk utilities. Credit rating downgrades by S&P and Moody's are relevant and also support a need for a change to the capital structure.

The Commission Panel requires TGI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

5.2 TGVI

The Applicants apply for a 40 percent common equity ratio for TGVI.

TGVI is also in an increasingly competitive environment. Ms. McShane says that TGVI faces higher risk than any of the major mature gas distribution utilities, and is more comparable to the smaller mature utilities and the greenfield gas distributors in the Maritimes (Exhibit B-1, p. 20). In particular, Ms. McShane views TGVI to be somewhat less risky than either of Enbridge Gas New Bruswick or Heritage Gas and to be in the same business risk class as Gazifiere Inc. and Natural Resource Gas. Ms. McShane also views TGVI to have higher business risk than FortisBC (Exhibit B-3, Vol. 2, IR 1.45.3). Ms. McShane provides the allowed common equity ratios of these utilities, which have a range from 40 percent to 50 percent and recommends a common equity range for TGVI of 45-50 percent.

The business circumstances of TGVI have changed since Ms. McShane's evidence was filed. TGVI has not sought a thicker common equity ratio or a higher return on equity as a result of the new circumstances, but submits that the circumstances have changed the business risks and provide further evidence of the reasonableness of the capital structure and return on equity that is being sought by TGVI.

The Applicants note that TGVI has the same allowed common equity as Enbridge, has no preferred shares, and is allowed approximately the same level of equity as Enbridge. Further, that the risk profiles of TGVI and Enbridge are not remotely similar (TGI/TGVI Submissions, p. 32).

Dr. Booth did not file evidence related to TGVI. The JIESC submits that there is no justification for changing the capital structure of TGVI at this time and that it does not make sense to do so.

Commission Determinations

The Commission Panel concludes that the appropriate common equity component in the capital structure of TGVI is 40 percent.

The Commission Panel requires TGVI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

6.0 RETURN ON EQUITY

6.1 The Applicants' Methodology

This Section considers the appropriate return on equity for a benchmark low-risk utility, and applies its determination in that regard to the return on equity for TGI and TGVI.

The Applicants introduce the evidence of Kathleen McShane (Exhibit B-1, Tab 2). Ms. McShane says that a fair return is one that provides a utility with the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

According to Ms. McShane these criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. Ms. McShane states that the two standards require the use of three tests used to develop her recommended fair return on equity for a benchmark low-risk utility:

- *Equity Risk Premium (ERP)* test, which is a generic term for a methodology that estimates the cost of equity as the sum of a directly observable yield on a security such as a government or corporate bond and a premium to compensate for the additional equity risk assumed by the investor;

- *Discounted Cash Flow (DCF)* test, which measures the equity investors' expected return as the dividend yield on a stock or group of stocks plus the expected growth in dividends in the long term; and

- *Comparable Earnings (CE)* test, which measures the experienced returns on book equity of firms that are of similar risk to the utility for which the regulator is setting the fair return (Exhibit B-1, Tab 2, lines 720-734).

6.1.1 <u>ERP Test</u>

Ms. McShane uses three methodologies to derive her equity risk premium as follows:

- Risk-Adjusted Equity Market
- Historic Utility
- DCF based

Risk-Adjusted Equity Market

Ms. McShane uses the period 1947-2004 to examine the average risk premium experienced in the Canadian, US and UK markets as follows (Exhibit B-1, Tab 2, Schedule 8):

	Stock Return	**Bond Return**	**Risk Premium**
Canada	12.1	6.9	5.3
United States	13.2	6.3	7.0
United Kingdom	14.9	8.9	6.0

Ms. McShane uses the arithmetic average that is the sum of each year's return divided by the number of years in the study. Ms. McShane addresses the issue of high bond returns in recent years by substituting her estimate of current long bond yields (5.25 percent) rather than historic average returns. From this she develops an indicated Canadian equity market risk of 6.75 percent, being the mid-point of a range of 6.25 percent to 7.25 percent. Ms. McShane applies a relative risk adjustment factor (beta) of 0.65, which she derives by developing "raw" betas from Canadian data which exclude Nortel. She then adjusts her "raw" beta using a formula used by major commercial suppliers of betas, which gives two-thirds weight to a stock's own beta and one-third weight to the market mean beta of 1.0. Thus, she arrives at a benchmark utility equity risk premium of 4.0 percent (Exhibit B-1, Tab 2, lines 1577-1968).

Historic Utility Equity Risk Premium

In Schedule 16 of her evidence, Ms. McShane observes actual utility equity (arithmetic average) risk premiums as follows:

1956-2004	Canada – gas and electric	4.4%
1947-2004	US – gas	6.0%
1947-2004	US – electric	5.0%

From which she determines that an appropriate historic utility equity risk premium for a benchmark low-risk utility to be in the range of 4.25-5.0 percent or approximately 4.75 percent (Exhibit B-1, Tab 2: lines 1985-2000).

DCF-Based Equity Risk Premium Test

Ms. McShane compares the estimated DCF cost of equity of seven US gas utilities over the corresponding 30-year U.S. Treasury yield on a monthly basis for the years 1993-2004 (Exhibit B-1, Tab 2, Schedule 18). This test indicates an average risk premium over the period of 4.2 percent. Since the corresponding bond return is 6.0 percent, Ms. McShane increases the observed premium to 4.7 percent to reflect her forecast yield on a 30-year (Canadian) government bond of 5.25 percent. At the same time, she tests the relationship between the spreads between U.S. long-term A-rated utility and 30-year U.S. Treasury yields and determines a utility risk premium of 4.3 percent. Ms. McShane settles on a mid-point of 4.5 percent for her DCF-based ERP test (Exhibit B-1, Tab 2, line 2140).

Financing Flexibility Allowance

To each of the three risk premiums developed by her tests, Ms. McShane adds a Financing Flexibility Allowance of 50 basis points. This allowance is intended to cover three aspects:

- flotation costs;
- a cushion for unanticipated capital market conditions; and
- a recognition of the fairness principle.

Ms. McShane's ERP test results are summarized as below (Exhibit B-1, Tab 2, p. 83):

Risk-Free Rate	5.25%
Equity Risk Premium	4.0-4.75%
"Bare-Bones" Cost of Equity	9.25-10.0%
Financing Flexibility Allowance	0.50%
Return on Equity	9.75-10.5%

6.1.2 DCF Test

Ms. McShane describes "the Discounted Cash Flow approach as proceeding from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows."

Due to the dearth of quoted utility companies in Canada and analysts' forecasts thereof, Ms. McShane applies her test to a sample of 14 relatively low-risk U.S. gas and electricity utilities that were included to serve as a proxy for a Canadian low-risk benchmark utility (Exhibit B-1, Tab 2, Appendix C). To determine investors' growth expectations, Ms. McShane uses both Value Line (an independent research firm) forecasts of earnings growth as well as I/B/E/S (the major data base that provides long term consensus forecasts) consensus forecasts of utility equity analysts. Ms. McShane found no evidence of upward bias in the I/B/E/S consensus forecasts; indeed, she cites studies which find that investment analysts' forecasts serve as a better surrogate for investors' expectations than historic growth rates.

In her first application of the DCF model, Ms. McShane applies a constant growth DCF model to her sample which results in a DCF cost of equity of 8.8 percent (Exhibit B-1, Tab 2, Schedule 20). Her second application of the DCF model uses analysts' forecasts for five years and a normal growth in the U.S. economy of 5.5 percent per annum thereafter, which gives a result of 9.7 percent (Exhibit B-1, Tab 2, Schedule 22).
Ms. McShane estimates an indicated "bare-bones" required return on equity in the range of 8.8-9.7 percent or approximately 9.25 percent. To her "bare bones" required return Ms. McShane adds 50 basis points. This is the same amount as that added to her ERP test, but arises for different reasons. Ms. McShane finds a "disconnect" between the DCF return investors expect to earn on the current market value of their common equity investments and what they expect the utility to earn on the book value of their investments. To mitigate this problem, she augments her DCF result by 50 basis points (Exhibit B-1, Tab 2, line 2393).

6.1.3 Comparable Earnings Test ("CE")

Ms. McShane describes the CE as "arising from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk."

To select a sample of Canadian companies of reasonably comparable investment risk to a benchmark low-risk utility, Ms. McShane takes all 432 companies on the Toronto Stock Exchange ("TSX") in Global Industry Classification Standard sectors 20-30 (being Industrials, Consumer Discretionary and Consumer Staples). From this list she removes companies which, in the period 1993-2003 had i) missing or negative common equity (368 companies); ii) paid no dividend in any year (21 companies); and iii) thinly traded companies, companies with betas > 1.0, companies with returns with a standard deviation of +/- -1 from average, ranked high risk or speculative, or unrated (17 companies) to arrive at her sample of 17 low-risk Canadian industrials

(Exhibit B-1,Tab 2, Appendix D).

Ms. McShane chooses the period 1993-2004 on the grounds that it covers an entire business cycle and should be representative of a future normal cycle. Ms. McShane assesses the possible need to adjust the results of her CE tests based on a review of the 17 companies' bond ratings, stock ratings and adjusted betas. Accordingly she adjusts the results of her CE tests which had indicated average levels of returns on book equity in the 13 to 13.5 percent range, down to "no less than 13 percent" (Exhibit B-1, Tab 2, line 2540).

6.1.4 <u>Summary</u>

To arrive at her indicated return on equity for a benchmark low-risk utility Ms. McShane applies an "indicative" weighting of 75 percent to her market based tests (ERP and DCF) and 25 percent to CE. As Ms. McShane points out "the answer is not going to come out to four places. Cost of equity doesn't lend itself to that level of precision" (T4: 506). Her indicated return on equity for a benchmark low-risk utility is 10.5 percent, or a premium of 5.25 percent over her estimate of a long Canada bond of 5.25 percent (Exhibit B-1, Tab 2, line 2573).

Ms. McShane addresses the ROE for TGVI as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return. Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium proposed for TGVI is reasonable" (Exhibit B-1, Tab 2, pp. 21-2).

6.2 The Intervenors' Methodology

The Intervenors filed the evidence of Dr. Booth, CIT Chair in Structured Finance and Professor of Finance at the Joseph L. Rotman School of Management at the University of Toronto (Exhibit C2-6). Dr. Booth uses the Capital Asset Pricing Model ("CAPM") to derive his estimate of the MRP, and tests the result with a DCF test of U.S. utilities followed by Standard & Poors.

6.2.1 MRP Test

Dr. Booth uses the period 1956-2004 to determine that the Canadian market risk premium of equities over long-term bonds has averaged (on an arithmetic basis) 2.70 percent. Extending the period examined back to 1924 produces a Canadian market risk premium of 5.21 percent. Dr. Booth estimates the current market risk premium to be 4.5 percent.

Dr. Booth examines the betas for utilities based in Canada for a number of five-year periods ending 1984 to 2004, but finds the data distorted by a number of factors, including the market crash of 1987 and the technology boom and bust of 2000 and 2001. Accordingly, for beta he estimates a reasonable range for normal market conditions going forward to be 0.45 to 0.55, which would imply a risk premium in the 2.025 percent to 2.475 percent range, which he adds to his long Canada bond yield forecast of 5 percent to produce an estimate in a range of 7.0 to 7.5 percent.

In addition to his "Classic CAPM" estimate, Dr. Booth uses a two factor CAPM model, which adjusts for estimation problems in the CAPM by directly incorporating the risk of long Canada bonds through a term or interest rate risk premium. The result of this second test produces an estimation of the fair return of 7.25 percent. Dr. Booth places equal weight on both CAPM estimates and took the average (7.25 percent) as being a reasonable estimate. To this estimate he adds a 50 basis point flotation cost allowance to produce a best estimate of 7.75 percent for a 275 basis point utility risk premium (Exhibit C2-6, p. 60).

6.2.2 Other Tests

Dr. Booth did not perform any other test to determine a fair return on equity. He did however, examine the DCF estimates for U.S. utilities covered by Standard & Poors for the period 1978-2004 from which he estimates an average return on equity of 10.17 percent from which he deducts the average U.S. Treasury of yield of 7.97 percent to determine a 220 basis point U.S. utility risk premium (Exhibit C2-6, Appendix C).

6.3 Discussion

Considerable evidence was before the Commission Panel as to the most suitable methodology to determine a fair return on equity for a benchmark low-risk Canadian utility. Much of the evidence comprises detailing the shortcomings of each of the methodologies in general and of the witness's applications of the concepts in particular.

The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return. The concept became embedded in Canadian regulatory methodology with the adoption by many regulatory bodies of the AAM whereby an individual utility's return on equity could be adjusted each year by reference to the change in the Risk Free cost of capital (namely the forecast long Canada bond yield). The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes with the result that in Canada's most recent generic cost of capital hearing, neither method was accorded any weight by the AEUB in its determination of a generic return on equity. In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions [Exhibit B-3E (Vol. 4), Appendix 74.1].

In the words of Ms. McShane: "I believe that … none of the tests is so superior (sic) to the others that it should be discarded in favour of just using one or two tests … Each test should be viewed as providing some perspective on what a fair return is" (T3: 377).

The Applicants in their submission argue that "A fair and reasonable return is not an arithmetic exercise; no approach is the determination of a fair and reasonable return is perfect. Although the use of a simple test may be appealing in its simplicity, it must be realized that the concept of a fair return is not that simple … TGI and TGVI submit that the Commission should consider all three approaches and give weight to each …" (TGI/TGVI Submissions, p. 35, para. 119).

6.3.1 ERP

Conceptually, the ERP methodology has a great deal of appeal to a regulator. It is derived from the CAPM, which was described in Exhibit B-21 being Chapter 7 of *Financial Theory and Corporate Policy* by Copeland and Weston. It requires the derivation of a risk free rate; an observed risk premium, being the difference between returns on common stocks and government bonds; and a factor known as beta, which is the coefficient of a portfolio or stock's volatility compared to the market as a whole. The Applicants outline the following shortcomings of the CAPM as it is applied to the derivation of an ERP:

Risk-Free Rate

The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

- the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
- yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
- long-term government bond yields are not risk-free; they are subject to interest rate risk (Exhibit B-1, Tab 2, Appendix A, p. 2).

Equity Market Risk Premium

The equity market risk premium is typically measured largely by reference to historic data. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future risk premium (Exhibit B-1, Tab 2, Appendix A, p. 3).

A decade by decade review of Canadian historic risk premiums shows a wide range of realized risk premiums, which would indicate the desirability of using longer rather than shorter periods to measure the premiums, as follows:

Time Period	Stock Returns	Bond Returns	Risk Premiums
1940s	10.0%	3.9%	6.0%
1950s	17.0%	0.4%	16.5%
1960s	10.8%	2.9%	7.9%
1970s	12.1%	6.1%	6.0%
1980s	13.1%	13.7%	-0.6%
1990s	11.6%	11.8%	-0.2%
1995-2004	11.2%	10.9%	0.2%
1947-2004 i)	12.0%	6.9%	5.3%
1956-2004 ii)	10.7%	8.0%	2.7%

i) used by Ms McShane
ii) used by Dr Booth (Schedule 1)

In addition, certain problems exist in Canada but not in the United States when it comes to measuring historic risk premium data. The achieved equity market risk premiums in Canada have been reduced by the performance of the government bond market. The change in Canada's fiscal performance over the past decade, leading to the recent low levels of interest rates, indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns, and therefore understates the future equity risk premium (Exhibit B-1, Tab 2, Appendix A, p. 4).

The Canadian equity market is less liquid, less diverse and less populous than the U.S. equity market. The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies (Exhibit B-1, Tab 2, Appendix A, p. 4).

Canadian equity data were "backcast" in 1976 upon the creation of the TSE 300 back to 1956. Accordingly, data prior to 1956, and to a lesser extent data between 1956 and 1976, may be less consistent (T6: 926).

Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

- the assumption that all risk for which investors require compensation can be captured and expressed in a single variable;
- the only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and

- the assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement.

Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative (Exhibit B-1, Tab 2, Appendix A, p. 5).

6.3.2 DCF

Dr. Booth points out the shortcomings of the DCF methodology. At page 58 of his testimony he states "It is generally accepted that analysts' earnings forecasts are biased high…This conflict of interest has been most evident in the Internet and Technology fiascos of the late 1990s, when prominent analysts issued strong buy recommendations on the way up and kept them in place on the way down and got sued in the process" (Exhibit C2-6, p. 58).

6.3.3 CE

In Appendix B of his evidence, Dr. Booth identifies five basic problems with the earned rate of return, namely:

- It is an accounting rate of return.
- It is an average not a marginal rate of return.
- It is earned on historic accounting book equity that does not reflect what can be earned on investments today.
- It is based on non-inflation adjusted numbers.
- It varies with the firms selected in the "comparable earnings" sample (Exhibit C2-6, Appendix B).

6.4 Commission Determinations

6.4.1 Two Standards

The Commission Panel accepts the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other. Accordingly, the Commission Panel will seek to give weight to each of the three methods placed before it in determining a suitable return for a benchmark low-risk utility.

6.4.2 Relevance of Other Board Decisions

All parties refer in their evidence and their submissions to decisions of other regulatory boards in Canada concerning fair returns. The JIESC warns of the danger of circularity resulting from a regulatory board "relying on what other boards have done." The JIESC continues:

> "On the other hand, one cannot totally ignore the immense amount of effort that has gone into determining fair returns by the NEB, in its generic ROE proceeding, and the AEUB, in its recent generic ROE and capital structure hearing.
>
> The AEUB hearing is the most recent and largest generic ROE hearing ever held in Canada. It went for 33 hearing days, involved 11 utilities, and heard from six expert witness panels.
>
> The AEUB and the NEB decisions should not be applied blindly by this Commission. However, they should be considered carefully, as should evidence of market acceptance of the allowed returns, and the acceptability of their awards to investors." (JIESC Submission, pp. 7-8)

At the November 2005 consensus risk free rate for 2006 of 4.79 percent the returns allowed for 2006 under current mechanisms are as follows:

BCUC – Terasen Gas Inc.	8.29%
NEB – Generic	8.89%
AEUB – Generic	8.93%
Ontario*	8.71%
Newfoundland	8.77%

* October 2005 Consensus
Source: Exhibit B-26

The Commission Panel's view is that it holds generic hearings into a fair return on such an infrequent basis, that there is little danger of circularity should it consider the returns allowed in other jurisdictions to ensure that the return it allows for 2006 is in line with returns allowed to benchmark low risk utilities in other jurisdictions.

6.4.3 Globalization

The Applicant states that since 1994 "Globalization of capital markets means that Canadian utilities are competing for capital with alternative investments world-wide. Globalization of capital markets provides Canadian investors opportunities for higher returns at similar risk levels than available in the domestic market. The returns allowed for Canadian utilities need to recognize that Canadian investors' opportunities are not limited to domestic investments" (Exhibit B-1, Tab 2, p. 5).

Dr. Booth submitted a monograph propounding the thesis that globalization or diversification reduces risk and market risk premium in both markets (Exhibit C2-6, Appendix D).

Dr. Booth, under cross-examination, states, “I generally believe that the US estimates both for the market risk premium and the US estimates from US regulated gas and electric utilities are higher than they would be for Canada. … I would say that they’re too high, which means that you cannot take them directly and apply them in Canada. … I would say they’re indicative, but my personal opinion would be that they are too high” (T6: 820).

During cross-examination Ms. McShane stated “And so there are a couple of different points: one, that there are opportunities (sc for investors to commit capital globally) and two, that in measuring the risk premium, we need to look beyond Canadian data” (T4: 424).

The Commission Panel agrees with this bifurcation. On the first issue the Commission Panel agrees that while it is now possible for Canadian investors to commit their entire retirement savings capital offshore, there is no evidence that they have been in a huge hurry to do so. Canadian investors face a considerable foreign exchange risk when investing offshore and the Commission Panel does not believe that they set this risk aside on the grounds that, in a perfect world, it should be capable of being hedged or otherwise diversified away.

The Commission Panel is not convinced that the Federal Government’s relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

As to the second issue, the Commission Panel is prepared to accept the use of historical and forecast data of U.S. utilities when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results. The Commission Panel bases this view on the fact that the U.S. and Canadian economy and capital markets are closely integrated.

6.4.4 Market to book ratios and acquisition premiums

In his evidence, Dr. Booth addresses the issue of market to book ratios of utility companies as follows:

> “This process is akin to someone investing in a savings account where a judge has to determine the correct savings rate each period that can be withdrawn from the fund. The important implication is that if the judge (regulator) is successful then the savings will always be worth their original investment. This is the meaning of the basic result in finance that fair means that the market to book ratio equals one. The only thing different about utilities, as compared to the savings example, is that there is some very minor business risk” (Exhibit C2-6, p. 74).

In Schedule 30 of his evidence, Dr. Booth graphically tracks the market to book ratios of a number of utility holding companies in Canada over the period. In addition, he observes the premiums paid by companies to acquire utility companies or utility assets and reaches the conclusion that regulatory bodies have been overly generous in their allowed returns on equity. In particular the Intervenors point to the acquisition of the shares of TI by KMI at an estimated market to book ratio of 2.7 to 1 to demonstrate that the Commission's formulaic approach to setting returns on equity has been overly generous and demonstrates that no upward revision to the existing ROE is warranted. Indeed, they argue that the Commission Panel accept Dr. Booth's recommendation, which would lower the benchmark return on equity.

Market to book ratios are a function of a stock's price divided by the book value of a share of its common equity. A stock's price is a function of what the market will pay for it and is either expressed by analysts and investors as a multiple of earnings or in a utility's case as the yield on its dividend. In neither case has a regulatory body any degree of control over the quantum of either the multiple or the actual dividend paid (McShane, T3: 139). Evidence before the Commission Panel is that market to book ratios of utilities (especially in the U.S.) have been below parity in the past. The Commission Panel agrees with Copeland and Weston (see Section 6.3.1 above) that all investors select efficient portfolios and that the market is simply the sum of all investors' individual holdings. Accordingly, the price paid for a utility share will vary over time depending on the changes in individual risk tolerances. The proper application of the CAPM model should remove the possibility of over generous returns, but over time will not prevent the market from valuing a utility's stock at prices which are both greater than and lower than its book value.

So far as concerns acquisition premiums, the Commission Panel has addressed the Kinder Morgan acquisition elsewhere in this Decision. So far as concerns other acquisitions the Commission Panel is mindful of the AEUB Panel's decision:

> "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.
>
> …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 … in recent years gives the Board some comfort that its recent ROE awards have not been too low" (Exhibit A3-1, p. 28).

The Commission Panel agrees with the AEUB that acquisition premiums may result from a number of strategic factors which are unrelated to the establishment of a fair return for a benchmark low-risk utility. The Commission will continue its practice of allowing utilities subject to its jurisdiction, to earn a fair return on the value of their investment in property, the value of which does not include a premium on acquisition.

6.4.5 ERP

It is clear the ERP methodology is the "gold standard" for Canadian regulators and the Commission Panel will give primary weight to its application and results. In doing so, however, the Commission Panel will need to apply judgment to the evidence before it.

CAPM Method

Risk Free Rate

For the purposes of establishing a return on equity, the Commission Panel accepts the consensus 30-year bond yield estimate for 2006, of 5.25 percent proposed by Ms. McShane. In Section 3 of the Decision, the Commission Panel discusses the methodology it should follow in effecting the transition of its present AAM to that which it now finds appropriate.

Arithmetic vs. Geometric Average

The Intervenors introduced the concept of the use of a geometric, rather than an arithmetical average to calculate the total returns on stocks and bonds (Exhibit C2-6, Appendix E, p. 1-3). The Applicant advocates the use of the arithmetic average, citing Ibbotson Associates "the expected equity risk premium should always be calculated using the arithmetic mean" (Exhibit B1, Tab 2).

The Commission Panel notes that the AEUB in its Generic Cost of Capital decision stated:

> "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" (Exhibit A3-1, p. 19).

Accordingly, the Commission Panel accepts the use of the arithmetic average for the purpose of determining the MRP in this hearing.

Market Risk Premium (MRP)

The Commission Panel observes that the evidence before it consists of the following average Market Risk Premium percentages:

		Canada	**US**
Applicant	1947-2004	5.3	7.0
Intervenor	1956-2004	2.70	4.65

and that both witnesses make adjustments to these results to arrive at their recommendations. In the Commission Panel's view a MRP of 5.8 percent is appropriate, given the Canadian experienced premiums since the Second World War, adjusted upwards in part to recognize both the fact that bond returns will most likely decrease in future years, and in part to recognize U.S. returns. Dr. Booth's two-factor model is not helpful in assisting the Commission Panel in determining an appropriate MRP.

Beta

The Commission Panel agrees with the evidence that the estimation of betas using actual five-year data ending December 31, 2004 (five years being the typical period for calculating betas) would give unreliable results given the technology boom followed by the bust in the years 2000 and 2001. Both witnesses were obliged to make considerable adjustments to arrive at recommended betas, Ms. McShane to her 0.60 to 0.70 and Dr. Booth to his 0.45 to 0.55. The Commission Panel believes that an appropriate estimate of beta or the relative risk factor of a benchmark low risk factor versus the overall equity market is 0.50. The Commission Panel is hopeful that such adjustments will not be necessary since the five-year data no longer include the technology boom/bust.

Historic Utility Risk Premium Test

The Commission Panel believes that this test avoids the estimation of a beta and thus suffers from one less shortcoming than the MRP test. On the basis of Ms. McShane's evidence that utility risk premiums in Canada over the period 1956 to 2004 were 4.4 percent, the Commission Panel is prepared to give weight to this number in arriving at its ERP.

DCF-Based Equity Risk Premium Test

The Commission Panel believes that Ms. McShane's sample of seven U.S. A-rated pure-play gas distribution companies, which indicates an average risk premium of 4.2 percent, is too small to use other than as a check on her other findings.

Financing Flexibility Adjustment

Both Ms. McShane and Dr. Booth add a Financing Flexibility Adjustment of 50 basis points to their ERP test results. In Ms. McShane's view the adjustment is necessary to cover flotation costs; a cushion for unanticipated capital market conditions and recognition of the fairness principle (Exhibit B-1, Tab 2, line 2160). Dr. Booth added a 50 basis point flotation allowance (Exhibit C2-6, p. 50). Both witnesses agree that the ERP test produces a bare bones cost of capital which should result in a market to book ratio of one. In Ms. McShane's words, "At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity" (Exhibit B-1, Tab 2, p. 82).

Dr. Booth observes that flotation costs can be calculated using the constant growth model and that the allowance could vary depending on a firm's dividend payment ratio and the ability to expense certain issue costs for tax purposes. He does, however, note at page 50 of his evidence "Note that with 5% issue costs, the idea is that the stock should sell at a market to book ratio of 1.053, so that it will net out to book value on any new issue. With utility market to book ratios vastly in excess of 1.052 it is difficult to rationalize any flotation cost allowance, since it is unlikely that there will ever be any dilution" (Exhibit C2-6, Footnote 19).

He concludes "However, I normally add 50 basis points as a cushion to the direct estimates in line with this (sic) practice of many Boards" (Exhibit C2-6, p. 50).

The Commission Panel notes that this issue received some attention during the AEUB generic hearing, but that it was not enough to convince the AEUB to change the 50 basis point flotation cost allowance used in recent decisions (Exhibit A3-1, p. 29).

The Commission Panel tends to agree that it is difficult to rationalize any flotation cost allowance since there was little, if any, evidence placed before it of utilities trading at market to book ratios, which would justify a flotation cost allowance addition to their return on equity. Elsewhere in this decision the Commission Panel addresses market to book ratios and the need to establish a fair rather than lowest possible return. Accordingly, the Commission Panel will not automatically add a 50 basis point surcharge to whatever return it deems appropriate, but will exercise its judgment each time.

6.4.6 DCF Test

The Commission Panel notes that the DCF test is the most widely used test by regulatory bodies in the United States. Of the three methodologies before it, the DCF test is the only one to use current and prospective data to derive its results. The major criticism of the DCF method is that it relies on analysts' forecasts, which may be biased upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his observations mostly cover U.S. technology analysts and the scandal on Wall Street concerning inappropriate analyst behaviour in an investment banking milieu. The Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. Utilities covered by Standard & Poors, which included "multi-utilities" and energy marketing firms, should not be used as representative of U.S. utility returns. The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter. Accordingly, the Commission Panel will give weight to Ms. McShane's first DCF Test, which yielded an indicated return of 8.8 percent. The Commission Panel agrees that this is a "bare bones" cost of equity, to which the addition of a "pure" flotation allowance of 25 basis points is required.

6.4.7 Comparable Earnings

Ms. McShane continues her practice of including in her evidence a study of the returns on book equity earned by a sample of low risk Canadian industrials in the period 1993-2004. This would suggest that low risk companies in Canada are earning an average of approximately 13 percent on their book equity.

On cross-examination, Dr. Booth agreed that some of the "problems" with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non-inflation adjusted numbers. This leaves the sample selection itself. The Commission Panel recognizes that the sample selection can lead to very different results, which is why regulatory bodies are reluctant to re-embrace Comparable Earnings.

Dr. Booth reminded the Commission Panel that the last jurisdiction in Canada to use Comparable Earnings used to adjust the results as follows:

> "And Dr. Cannon tended to be the board (sc OEB) witness and he would do comparable earnings with market-to-book adjustments. And stretching my memory, but Ms. McShane I think estimated correctly that you'd look at rates of returns and try to work out what these rates of returns from non-regulated first would be if they had to have a market to book ratio of 1.5 or 1.2, which was sort of the target for regulated firm" (T6: 935).

The Commission Panel believes that there is not enough evidence before it to determine if such an adjustment is merited or how it might be accomplished. The Commission Panel is of the view that for these reasons it can give little or no weight to Ms. McShane's CE test results. However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings.

6.4.8 Conclusion

In the Commission Panel's view, the suitable return on equity for a benchmark low-risk utility is 9.145 percent, assuming a 30-year long Canada bond yield of 5.25 percent, for a premium of 3.895 percent.

6.5 Impact of the Commission Panel's Determination

6.5.1 Impact on TGI

The Commission Panel determines that TGI is the benchmark low-risk utility. For 2006 TGI's ROE will be 8.80 percent viz 9.145 minus (.75*(5.25-4.79), on an equity component of capital structure of 35 percent, which the Commission Panel earlier determined to be appropriate. Based on Exhibit B-13, the Commission Panel believes the impact on TGI's 2006 revenue requirement will be a net increase of $1.9 million over TGI's approved 2005 revenue requirements, as follows:

	$ million
Increase in capital structure to 35%	4.742
Decrease in ROE to 8.80% from 9.03%	(2.842)
	1.900

6.5.2 Impact on TGVI

The Commission Panel determines that a suitable premium to TGVI over the benchmark low-risk utility ROE is 70 basis points. For 2006 TGVI's ROE will be 9.5 percent on an equity component of capital structure of 40 percent, which the Commission Panel earlier determined to be appropriate. Since TGVI was earning 9.53 percent in 2005, the net impact on TGVI's revenue requirement in 2006 will be approximately $1.7 million.

6.5.3 Other B.C. utilities

Other B.C. utilities whose ROE will be automatically affected by the Commission Panel's determination, effective January 1, 2006, include:

	Benchmark	**Premium**	**2006 ROE**
FortisBC	8.80	0.40	9.20
Pacific Northern Gas – W	8.80	0.65	9.45
Pacific Northern Gas – NE	8.80	0.40	9.20
BC Hydro (1)	8.80	0.00	8.80

(1) on a post-tax equivalent basis

Dated at the City of Vancouver, in the Province of British Columbia, this 2nd day of March 2006.

Original signed by:
Robert H. Hobbs
Panel Chair

Original signed by:
Anthony J. Pullman
Commissioner

Views of Commissioner Milbourne

I have had the opportunity of reading the determinations and reasons of the majority of the Panel in final draft form.

With the exception noted below, I respectfully dissent from my colleagues' findings with respect to the Capital Structure and Return on Equity for TGI and TGVI. I do not find that the totality of evidence before the Panel, and the authorities cited, make a persuasive case for any change from the status quo.

I concur with their findings in Section 3 with respect to the Annual Adjustment Mechanism. This change, if adopted for changes in long Canada bond yields above and below 6 percent would accordingly raise the allowed ROE for 2006 from 8.29 percent to approximately 8.60 percent for the Low Risk Benchmark Utility.

Original signed by:
R.J. Milbourne
Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-14-06

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by
Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") ("the Companies")

To Determine the Appropriate Return on Equity ("ROE") and Capital Structure to be Used in Setting the Rates of the Companies Commencing January 1, 2006

and

To Review and Revise the Automatic Adjustment Mechanism Used in Calculating the ROE Allowed in Rates for Public Utilities Regulated by the BC Utilities Commission
("the Application")

BEFORE: R.H. Hobbs, Chair
R.J. Milbourne, Commissioner — March 2, 2006
A.J. Pullman, Commissioner

O R D E R

WHEREAS:

A. On July 22, 2004, TGI wrote to the Commission requesting that the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review would be appropriate in the Fall of 2005 in time for implementation January 1, 2006; and

B. By Application dated June 30, 2005, the Companies submit that: 1) the allowed returns on equity of both Companies should be increased to an appropriate level, 2) the common equity component in the capital structure of both Companies should be increased to properly reflect the risks of the Companies, and 3) the current ROE adjustment mechanism should be reviewed and revised to provide the Companies with a fair and adequate return on equity in future years; and

C. By Order No. G-69-05, the Commission established a Procedural Conference to be held on Wednesday, August 3, 2005 in Vancouver, B.C.; and

D. In a letter dated August 25, 2005, the Joint Industry Electricity Steering Committee ("JIESC") requested that the Chair decide not to sit on the Panel to avoid compromising the unbiased appearance of the proceeding and the procedural fairness all parties are entitled to expect; and

E. By Letter No. L-67-05 dated August 5, 2005, the Commission Panel defined the scope of the proceeding, determined that other utilities would not have the same status as other Intervenors in the proceeding, and established an approved Regulatory Timetable including an Oral Public Hearing to review the Application to commence on Monday, November 14, 2005; and

F. By Letter No. L-81-05 dated September 29, 2005, the Commission denied the request by the JIESC that the Chair should not sit on this matter; and

G. An Oral Public Hearing was held in Vancouver commencing on November 14, 2005 and ending on November 18, 2005; and

H. Written Argument was filed by the Companies on December 5, 2005 and by the Intervenors on or before December 20, 2005. Reply Argument was filed by the Companies on January 5, 2006 and an Oral Phase of Argument was held on January 17, 2006; and

I. The Commission Panel has determined that a change to the Capital Structures of the Companies, the Returns on Equity allowed a low-risk benchmark utility, and the utility-specific equity risk premium for TGVI is in the public interest.

NOW THEREFORE the Commission orders as follows to be effective January 1, 2006:

1. The appropriate common equity component allowed in the capital structure of TGI is 35 percent.

2. The appropriate common equity component allowed in the capital structure of TGVI is 40 percent.

3. The approved return on equity for the benchmark low-risk utility is 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent. For 2006 this results in an approved return on equity for TGI of 8.80 percent.

4. The approved return on equity for TGVI is 70 basis points greater than the benchmark low-risk utility return, namely 9.5 percent.

5. Other B.C. utilities whose returns on equity are established relative to that of the benchmark low-risk utility may adjust their rates accordingly subject to Commission approval.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of March, 2006.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

LIST OF APPEARANCES

G.A. FULTON	Commission Counsel
C. JOHNSON M. GHIKAS	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
P. MACDONALD	B.C. Old Age Pensioners' Organization Council of Senior Citizens' Organizations Federated Anti-Poverty Group End Legislated Poverty West-End Seniors Network Tenants Rights Action Coalition B.C. Coalition of People with Disabilities
G.K. MACINTOSH, Q.C. D. BENNETT	FortisBC Inc.
J.D.V. NEWLANDS	Elk Valley Coal Corporation
R.B. WALLACE	Joint Industry Electricity Steering Committee British Columbia Utility Customers
C. WEAFER	Commercial Energy Consumers Association of British Columbia
A. WAIT	Himself

J.W. Fraser R. Gorter E. Cheng D. Chong	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF WITNESSES

RANDY JESPERSEN SCOTT THOMSON DAVID BRYSON	Terasen Gas Inc. (Panel 1)
KATHLEEN MCSHANE	Terasen Gas Inc. (Panel 2)
DR. LAURENCE D. BOOTH	British Columbia Utility Customers: (Joint Industry Electricity Steering Committee, Commercial Energy Consumers Association of British Columbia The Lower Mainland Large Gas Users Association The British Columbia Old Age Pensioners' Organization et al.)

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated July 8, 2005 and Order No. G-69-05 establishing a Procedural Conference
A-2	Letter dated July 8, 2005 requesting the Regulated Utilities to provide their preliminary positions on the participation and the coordination of evidence of all regulated utilities
A-3	Letter No. L-58-05 dated July 19, 2005 regarding appointment of Commissioner
A-4	Letter dated July 21, 2005 advising that Commissioner O'Hara will not be appointed to the Panel for this Proceeding
A-5	Letter dated August 2, 2005 enclosing draft Regulatory Agenda for discussion at the Procedural Conference
A-6	Letter No. L-67-05 dated August 5, 2005 defining the scope for review of the Application and issuing an updated Regulatory Timetable
A-7	Letter dated August 8, 2005 to Terasen Gas and Terasen Gas (Vancouver Island) responding to the JIESC's request (Exhibit C2-2) for a full description of the Chair's involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues
A-8	Letter dated August 11, 2005 to Pacific Northern Gas Ltd. responding to its request for clarification of PNG's status pursuant to Commission Letter No. L-67-05
A-9	Letter and Commission Information Request No. 1 dated August 12, 2005 to Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
A-10	Letter dated August 26, 2005 requesting comments from Registered Intervenors on the JIESC request to have the Chair step down (Exhibit C2-3)
A-11	Letter dated September 13, 2005 and Commission Information Request No. 2
A2-1	Letter dated September 2, 2005 from Commission Counsel commenting on the JIESC request to have the Chair step down (Exhibit C2-3)

EXHIBIT LIST

Exhibit No.	Description
A-12	Letter dated September 29, 2005 – Reasons Regarding JIESC Request
A-13	Letter dated October 20, 2005 – Information Request No. 1 to Utility Customers
A-14	Letter dated November 10, 2005 – Commencement of Hearing
A-15	Letter dated November 10, 2005 – Appointment of Commissioner A.J. Pullman
A-15a	Commission Submission at Oral Hearing – Response to BCUC IR No. 1
A-16	Commission Submission at Oral Hearing – TGI Response to IR
A-17	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 2
A-18	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 3
A-19	Commission Submission at Oral Hearing – TGI-TGVI Cross Examination – Policy Panel
A-20	Commission Submission at Oral Hearing – BMO Nesbitt Burns – Consolidated Summary Sheet
A-21	Commission Submission at Oral Hearing – Adjustment to Cost of Service
A-22	Commission Submission at Oral Hearing – TGVI ROE Allowed and Achieved Calculation
A-23	Commission Submission at Oral Hearing – TGVI Statements of Earnings
A-24	Commission Submission at Oral Hearing – Witness Aid-Evidence Weights
A-25	Commission Submission at Oral Hearing – ICBC Statement of Investment Policy and Procedures
A-26	Commission Submission at Oral Hearing – Canadian Ratings Research Update-Terasen Inc. Purchase by Kinder Morgan Inc.
A-27	Submission At Oral Hearing – News Release From FortisBC Dated November 10, 2005 Announcing $100 Million Debenture Offering
A-28	Submission At Oral Hearing – Document From Standard & Poors Dated January 2002 Headed "S&P/TSX Capped Indices"

EXHIBIT LIST

Exhibit No.	Description
A-29	Letter dated December 19, 2005 approving the JIESC's request for an extension of time to file its closing argument material (Exhibit C2-22)
A3-1	Submission at Oral Hearing – Alberta Energy and Utilities Board-Generic Cost of Capital Decision dated July 2, 2004
A3-2	Submission at Oral Hearing -Decision of the Board of Commissioners of Public Utilities, Newfoundland and Labrador, in the matter of the 2003 general rate application filed by Newfoundland Power Inc., the Board order PU19-2003
A3-3	Submission at Oral Hearing - Decision of the Regis (Action Number D-99-11)
A3-4	Submission At Oral Hearing - Supreme Court Of Canada Decision re: Northwest Utilities
A3-5	Submission At Oral Hearing – B.C. Electric Railway Company Supreme Court Of Canada Decision Dated 1960
A3-6	Order No. G-126-05 and Negotiated Settlement dated November 30, 2005 on TGVI's 2006/07 Revenue Requirements Application

APPLICANT DOCUMENTS

Exhibit No.	Description
B-1	**TERASEN GAS INC and TERASEN GAS (VANCOUVER ISLAND) INC.** Application dated June 30, 2005 to determine the appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism
B-2	E-mail dated July 20, 2005 providing a letter from Terasen Gas (Whistler) Inc. and Terasen Gas (Squamish) Inc. in response to Commission letter of July 8, 2005 (Exhibit A-2)
B-3	Letter dated September 2, 2005 filing responses to Commission Information Request No. 1
B-4	Letter dated September 7, 2005 responding to the JIESC request that the Commission Chair step down from the Panel established to review the Return on Equity Application
B-5	Letter dated September 30, 2005 filing responses to the following

EXHIBIT LIST

Exhibit No.	Description
	Information Requests: Commission Information Request No. 2 Al Wait Information Request No. 1 Commercial Energy Consumers Information Request No. 1 JIESC-BCOAPO-CEC (Dr. Booth) Information Request No. 1 Vancouver Island Gas Joint Venture Information Request No. 1
B-6	Letter dated October 5, 2005 – Revised certain rate comparative Figures and Tables in June 30, 2005 Application
B-7	Letter dated October 20, 2005 – Information Request No. 1 to Dr. Laurence D. Booth
B-8	Submission at Oral Hearing – Direct Testimony of R.L. (Randy) Jesperson Direct Testimony of Scott Thomson Direct Testimony of David Bryson
B-9	Submission at Oral Hearing – Opening Statement on Behalf of TGI and TGVI
B-10	Submission at Oral Hearing – 2006 Forecast Allowed ROE & Capital Structure
B-11	Submission at Oral Hearing – 30yr Bond Issues in Canada with BBB rating
B-12	Submission at Oral Hearing – Recorded Actual TGI Volumes – TJs
B-13	Submission at Oral Hearing – Undertaking-Transcript Page 231
B-14	Submission at Oral Hearing – Undertaking Transcript Page 259
B-14A	Submission at Oral Hearing – Undertaking Transcript Page 807
B-15	Submission at Oral Hearing – Terasen Management's Discussion and Analysis dated November 3, 2005
B-16	Submission at Oral Hearing – Undertaking Transcript Page 259
B-17	Submission at Oral Hearing – Undertaking Transcript Page 260
B-18	Submission at Oral Hearing –Ratings Direct Research-Canadian Utility Regulation Reassessed as a Ratings Factor

EXHIBIT LIST

Exhibit No.	Description
B-19	Submission at Oral Hearing – Global Credit Research Document dated October 14, 2005
B-20	Submission at Oral Hearing – Kinder Morgan's Historical Equity and Debt/Total Capitalization Ratios
B-21	Submission at Oral Hearing – Financial Theory and Corporate Policy
B-22	Submission at Oral Hearing – Market and Individual Stock Graph
B-23	Submission at Oral Hearing – Commission Transcript dated April 12, 1994
B-24	Submission at Oral Hearing – GICS to Companies
B-25	Submission at Oral Hearing - Generic Roe Calculation For 2006 Based On Current Formula
B-26	Letter dated November 25, 2005 – ROE 2006 Estimates
B-27	Letter dated January 3, 2006 filing the December 19, 2005 Moody's Investors Service Announcement
B-28	Letter dated January 20, 2006 amending the TGI/TGVI January 19, 2006 letter regarding interest coverage discussed at page 1071 of the Transcript

INTERVENOR DOCUMENTS

Exhibit No.	Description
C1-1	**CENTRAL HEAT DISTRIBUTION LIMITED** - Notice of Intervention dated July 8, 2005 from John S. Barnes
C2-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** - Notice of Intervention dated July 13, 2005 from R.B. Wallace
C2-2	Letter dated August 5, 2005 to Commission Counsel requesting a full description of the Chair's involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues from the time the Chair joined West Kootenay, presumably some time before 1994 until he left Aquila in 2001 or 2002
C2-3	Letter dated August 25, 2005 requesting that the Commission Chair step down from the Panel established to review the Return on Equity Application

EXHIBIT LIST

Exhibit No.	Description
C2-4	Letter dated September 9, 2005 responding to Intervenor submissions
C2-5	Information Request No. 1 dated September 14, 2005
C2-6	Letter dated October 11, 2005 – Evidence of Dr. Laurence Booth
C2-7	E-mail dated November 4, 2005 – Responses to Terasen Gas Information Request No. 1
C2-8	E-mail dated November 4, 2005 – Responses to FortisBC Information Request No. 1
C2-9	E-mail dated November 4, 2005 – Responses to Commission Information Request No. 1
C2-10	Submission at Oral Hearing – Review of OEB Guidelines for setting ROE
C2-11	Submission at Oral Hearing – BMO Corporate Debt Research regarding Terasen Inc. – Kinder Morgan Acquisition Appears Credit Negative for Bondholders
C2-12	Submission at Oral Hearing – Globe and Mail clip from October 30, 2001 regarding “BC Gas financing proves it’s the silly season”
C2-13	Submission at Oral Hearing – TGI Credit Rating Report
C2-14	Submission at Oral Hearing – OEB September 7, 1993 Transcript
C2-15	Submission at Oral Hearing – Electric Load Forecast
C2-16	Submission at Oral Hearing – BMO Research Report regarding BC Gas to Acquire Centra Gas British Columbia
C2-17	Submission at Oral Hearing – RBC Capital Markets document dated August 10, 2005
C2-18	Submission at Oral Hearing – Corporate Financial Analysis
C2-19	Submission at Oral Hearing – Basic Variables-Single Year Changes Year-End to Year-End

EXHIBIT LIST

Exhibit No.	Description
C2-11A	Submission at Oral Hearing – Gas Distribution Sector-10 yr Indicative Spreads
C2-20	Submission at Oral Hearing – Public, Power & Utilities Bulletin dated August 10, 2005
C2-21	Responses to Undertakings at Transcript Volume 6, pp. 825, 827 and 903-4
C2-22	Letter dated December 14, 2005 requesting a one day extension to the filing of the JIESC Argument
C2-23	Letter dated December 21, 2005 requesting the Commission to re-open the evidentiary record
C2-24	Undertaking at Transcript Page 1054 - Letter dated January 22, 2006 regarding the issuance of Preferred Shares
C2-25	Undertaking at Transcript Page 1071 – Letter dated January 22, 2006 regarding Interest Coverage
C3-1	**THE BC OLD AGE PENSIONERS ORGANIZATION ET AL.** - Notice of Intervention dated July 15, 2005 from Jim Quail, The British Columbia Public Interest Advocacy Centre
C3-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C4-1	**ENBRIDGE GAS DISTRIBUTION** - Notice of Intervention dated July 18, 2005 from Lorraine Chiasson
C4-2	E-mail dated July 26, 2005 regarding Enbridge Gas Distribution contact information
C5-1	**ELK VALLEY COAL CORPORATION** - Notice of Intervention dated July 20, 2005 from J. David Newlands
C6-1	**UNION GAS LIMITED** - Notice of Intervention dated July 21, 2005 from Patrick McMahon

EXHIBIT LIST

Exhibit No.	Description
C7-1	**INLAND INDUSTRIALS** - Notice of Intervention dated July 25, 2005 from David Bursey, Bull, Housser & Tupper LLP
C8-1	**CANADIAN OFFICE AND PROFESSIONAL UNION** - Notice of Intervention dated July 21, 2005 from Pat Junnila
C9-1	**LOWER MAINLAND LARGE GAS USERS ASSOCIATION** - Notice of Intervention dated July 26, 2005 from Christopher Weafer, Owen•Bird
C10-1	**ALAN WAIT** - Notice of Intervention dated July 26, 2005
C10-2	E-mail dated July 26, 2005 with reasons for intervention
C10-3	Information Request No. 1 dated September 14, 2005
C11-1	**RANDALL JANG** - Notice of Intervention dated July 28, 2005
C12-1	**FORTISBC INC.** - Notice of Intervention dated July 28, 2005 from George Isherwood
C12-2	Letter dated October 20, 2005 – Information Request No. 1 to JIESC, CEC and BCOAPO
C12-3	Submission at Oral Hearing – Rates of Return on Common Equity at Various Bond Yield Levels
C13-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES** - Notice of Intervention dated July 26, 2005 from Stirling M. Bates
C14-1	**TRANSCANADA PIPELINES LIMITED** - Notice of Intervention dated July 28, 2005 from James Bartlett and Patrick M. Keys
C15-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** - Notice of Intervention dated July 29, 2005 from Tony Morris

EXHIBIT LIST

Exhibit No.	Description
C15-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C16-1	**AVISTA ENERGY CANADA** - Notice of Intervention dated July 29, 2005
C17-1	**HEATING, VENTILATING & COOLING ASSOCIATION** – Web registration dated July 29, 2005 from Nelle Maxey
C17-2	Letter of Comment dated August 10, 2005
C17-3	Letter dated August 26, 2005 supporting the JIESC's request that the Chair step down from the Panel
C18-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA** – Notice of Intervention dated July 29, 2005 from Christopher Weafer
C18-2	Information Request No. 1 dated September 14, 2005 from Christopher Weafer
C19-1	**PACIFIC NORTHERN GAS LTD.** – Notice of Intervention and Comments on the Generic ROE proceeding dated July 28, 2005 from Craig Donohue
C19-2	Letter dated August 10, 2005 requesting clarification of PNG's status in light of Commission Letter No. L-67-05
C20-1	**VANCOUVER ISLAND GAS JOINT VENTURE** – Notice of Intervention dated August 26, 2005 from Karl E. Gustafson, Lange Michener
C20-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C20-3	Information Request No. 1 received September 15, 2005
C21-1	**HOWE SOUND PULP AND PAPER LIMITED PARTNERSHIP** – Notice of Intervention dated August 30, 2005 from Pierre G. Lamarche

EXHIBIT LIST

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	Letter dated July 8, 2005 from the Rental Owners and Managers Association of BC requesting Interested Party status
LETTERS OF COMMENT	
E-1	Letter of Comment dated July 22, 2005 from Reiner Teschinsky Letter of Comment dated August 30, 2005 from Reiner Teschinsky

GLOSSARY AND ABBREVIATIONS

Acronym	**Term**
Act or UCA	Utilities Commission Act
AEUB	Alberta Energy and Utilities Board
“Applicants”, “Companies”	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
“Application”	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. - Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism dated June 30, 2005
AAM	Automatic Adjustment Mechanism
BC Gas	BC Gas Utility Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	The British Columbia Old Age Pensioners’ Organization et al.
BCUC or Commission	British Columbia Utilities Commission
CAPM	Capital Asset Pricing Model
CBRS	Canadian Bond Rating Service
CCRA	Commodity Cost Reconciliation Account
CE	Comparable Earnings
CEC	Commercial Energy Consumers Association of British Columbia
CRTC	Canadian Radio-Television and Telecommunications Commission
DBRS	Dominion Bond Rating Service
DCF	Discounted Cash Flow
Enbridge or EGDI	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick
ERP	Equity Risk Premium
GJ	Gigajoule
GMI	Gaz Metro
IBES	Institutional Brokers Estimates System
ICP	Island Cogeneration Project
JIESC	Joint Industry Electrical Steering Committee

GLOSSARY AND ABBREVIATIONS

KMI	Kinder Morgan, Inc.
MCRA	Midstream Cost Reconciliation Account
Moody’s	Moody’s Investors Service
MRP	Market Risk Premium
NEB	National Energy Board
OEB	Ontario Energy Board
O&M	Operating and Maintenance Costs
PBR	Performance-Based Rates or Performance Based Rate-Making
PNG	Pacific Northern Gas Ltd.
RDDA	Revenue Deficiency Deferral Account
ROE	Return on Equity
RSAM	Revenue Stabilization Adjustment Mechanism
S&P	Standard & Poors
Terasen Gas or TGI	Terasen Gas Inc.
TGS	Terasen Gas (Squamish) Ltd.
TGVI	Terasen Gas (Vancouver Island) Inc.
TI	Terasen Inc.
TJ	Terajoule
Union	Union Gas Limited
Value Line	Value Line, Inc.
VINGPA	Vancouver Island Natural Gas Pipeline Agreement

TERASEN GAS INC.
and
TERASEN GAS (VANCOUVER ISLAND) INC.

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
June 2005

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I. INTRODUCTION AND EXECUTIVE SUMMARY

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am a Senior Vice President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies, in more than 130 proceedings in Canada and the U.S. My professional experience is provided in Appendix E.

Terasen Gas Inc. (Terasen Gas) and Terasen Gas (Vancouver Island) Inc. (TGVI), are requesting that the British Columbia Utilities Commission (BCUC or Commission) undertake a review of the benchmark low risk utility return on equity (ROE), the capital structure that Terasen Gas requires to qualify as a low risk benchmark utility, a reasonable capital structure and equity risk premium for TGVI, and the automatic adjustment mechanism used to set the ROE. The purpose of my testimony is to:

1. Define a benchmark low risk utility and the corresponding benchmark utility return;

2. Compare Terasen Gas to the benchmark utility in light of its business risks and propose a capital structure that would equate Terasen Gas to the benchmark utility;

3. Recommend a benchmark utility return based on current and prospective capital market conditions that will meet the three standards of a fair return.

4. Assess the reasonableness of the proposed capital structure and equity risk premium (relative to the benchmark utility) for TGVI, and,

5. Recommend changes to the existing automatic adjustment mechanism.

B. EXECUTIVE SUMMARY

1. The key objective of this report is to develop and recommend a fair and reasonable return for a benchmark low risk utility under current economic and capital market conditions. The return on equity that results from the analysis applies to a utility whose total (combined business and financial) risks qualify it as low risk. Stated differently, the benchmark low risk utility return represents the return required at a particular level of total risk.

If a specific utility faces a higher level of total risk than the benchmark, whether because of its business risks, financial risks or both, the benchmark low risk return is not directly applicable. In that case, either an adjustment to the allowed capital structure is required, to lower the utility's financial risks, an adjustment to the benchmark return on equity is required, to provide compensation for the utility's higher combined business and financial risks, or alternatively, adjustments to both common equity ratios and allowed return on equity are required.

2. The Commission introduced the concept of the benchmark low risk utility in its first generic return on equity decision in 1994. Since that time Terasen Gas, at an allowed common equity ratio of 33%, has been equated to the benchmark low risk utility. Since the initial generic ROE decision in 1994, Terasen Gas' business risks have risen, in particular due to changes in its competitive environment. The

allowed capital structure has become weaker with the redemption of its preferred shares, which, in 1999, accounted for 9.4% of the regulated capital structure. Its allowed capital structure, in conjunction with the level of its recent allowed returns, do not provide the company sufficient financial flexibility. Its peers, with whom it competes for capital, are allowed stronger capital structures. Thus a stronger capital structure is warranted.

The allowed common equity ratios of other major gas distributors which are comparable in business risk to Terasen Gas are in the range of 35-38%. The capital structures all contain some preferred shares. Further, the regulated capital structures of Canadian utilities are generally perceived to be weak relative to their global peers. In my opinion, for Terasen Gas to qualify as a benchmark low risk utility, its allowed common equity ratio should be in a range of 35-40%.

3. The proposed common equity ratio and equity risk premium for TGVI relative to the low risk utility benchmark are 40% and 75 basis points respectively. TGVI faces considerably higher business risks than a benchmark utility. In my opinion, an equity ratio of no less than 45-50% is required to equate TGVI, to the benchmark utility. Thus, while TGVI's proposed 40% equity ratio is not unreasonable, it is not sufficient for TGVI to attract the benchmark utility return. At a 40% equity ratio, an incremental equity risk premium of approximately 90 basis points above that of the benchmark utility is required to provide full compensation for TGVI's risks. The proposed 75 basis point equity risk premium is, in my view, reasonable.

4. The typical allowed return on equity in Canada for utilities of similar risk to the low risk benchmark in 2005 was at the relatively low level of about 9.5%. By comparison, the allowed ROE for a benchmark low risk utility in British Columbia was only 9.03%.

The following demonstrates that the combined allowed return and common equity ratio for each of Terasen Gas, FortisBC and Pacific Northern Gas is lower than the average of its closest Canadian comparables.

Table 1

	Allowed Common Equity Ratio (1)	**Allowed Return at Forecast 5.25% Long Canada** (2)	**Weighted Equity Return Component** (Col 1 x Col 2)
Terasen Gas	33.0%	8.75%	2.89%
Comparables	36.5%	9.25%	3.38%
TGVI	35.0%	9.25%	3.24%
Comparables	43.2%	10.82%	4.74%
FortisBC	40.0%	9.15%	3.66%
Comparables	40.6%	9.27%	3.77%
Pacific Northern Gas	36.0%	9.40%	3.38%
Comparables	43.5%	9.34%	4.06%

5. Since the Commission first introduced the benchmark low risk utility return and the automatic adjustment mechanism for return on equity in 1994, the following conditions have changed, each of which points to the need for higher allowed returns for Canadian utilities generally, and for B.C. utilities specifically.

   a. The equity market risk premium, that is, the difference between the expected return on the equity market composite and the expected return on long Canada bonds, is higher; long Canada yields have declined significantly since the mid-1990s, while the expected value of the equity market return has not similarly declined. The resulting equity market risk premium is thus wider in today's low interest rate environment.

b. Globalization of capital markets means that Canadian utilities are competing for capital with alternative investments world-wide. Globalization of capital markets provides Canadian investors opportunities for higher returns at similar risk levels than available in the domestic market. The returns allowed for Canadian utilities need to recognize that Canadian investors' opportunities are not limited to domestic investments.

c. The spreads between utility and government of Canada bond yields are relatively high, despite robust debt markets. The high spreads – which are a function of utilities' combined business and financial risks – point to a perception of increased risk since the time the benchmark low risk utility return was initially set. The increased risk has not been reflected in the allowed returns.

d. A comparison between returns on equity for low risk industrial firms and allowed returns on book value for utilities reveals an increasing divergence. Low risk Canadian industrials are earning in the 13.0-13.5% range, while Canadian utilities are allowed to earn approximately 9.5%.

e. A comparison of the allowed returns for U.S. and Canadian utilities reveals a 100 basis point gap in favor of U.S. utilities, not explained by differences in risk or capital market conditions between the two countries. The higher allowed returns of U.S. utilities, in conjunction with materially thicker allowed common equity ratios, makes Canadian utilities relatively less attractive.

f. As long Canada bond yields have declined, capital market participants, particularly the Canadian debt rating agencies, have been singling out the relatively low allowed returns on equity and common equity ratios in citing the challenges faced by Canadian utilities.

6. The benchmark low risk utility return should be reset at a level of 10.5% (based on a forecast long Canada bond yield of 5.25%). The 10.5% return on equity reflects the results of the three tests that have been traditionally used to estimate a fair return: equity risk premium (ERP), discounted cash flow (DCF) and comparable earnings.

In weighing the evidence, the Commission needs to explicitly consider the distinction between the premise of the equity risk premium and discounted cash flow tests on the one hand, and the comparable earnings test on the other. The ERP and DCF tests estimate the minimum return that will allow the utility to attract equity capital. The comparable earnings test measures return on book value – the basis upon which allowed returns are set and earnings generated. A fair and reasonable return recognizes both the utilities' need to attract capital **and** its entitlement to the opportunity to earn returns commensurate with those achievable by comparable risk firms.

7. My application of the equity risk premium test comprises three separate tests. The first, the risk-adjusted equity market risk premium test, estimates the benchmark utility return indirectly by first estimating the risk premium for the equity market as a whole, and then estimating by how much that premium needs to be adjusted for the relative risk of a particular company or portfolio of securities. My estimate of the equity market risk premium, which recognizes today's low level of interest rates, is 6.0-6.5%. The relative risk factor for a benchmark low risk utility is 0.65. This ERP test produces an estimated benchmark utility equity risk premium of 4.0% at a forecast long Canada yield of 5.25%.

The utility equity risk premium can also be estimated directly by looking only at utility data. Analysis of historic utility equity risk premiums indicates a utility risk premium of approximately 4.75%.

A second utility-specific risk premium test makes use of the discounted cash flow (DCF) model. The DCF model lends itself to making forward-looking estimates of the utility cost of capital at a point in time. The DCF cost of equity is equal to the current dividend yield (dividend/price) plus investors' expectations of the long-term growth in the stock. With a time series of consistently developed DCF estimates and the corresponding yields on long government bonds, the relationship between utility cost of equity and interest rates can be tested. The estimated relationship indicates an approximately 60 basis point increase/decrease in the utility cost of equity when long government bonds increase/decrease by 100 basis points. The test also demonstrates that there is a positive relationship between utility bond spreads (utility bond yields minus long Canada yields) and the utility equity risk premium. In other words, a higher utility bond spread equals a higher utility equity risk premium. The DCF-based equity risk premium test indicates a utility equity risk premium of 4.3-4.7% at a long Canada yield of 5.25%.

The combination of the three equity risk premium tests indicates a reasonable ERP for a benchmark low risk utility is 4.0-4.75% at the forecast risk-free rate of 5.25%. The resulting cost of equity is 9.25-10.0%

8. The ERP test is a market test that estimates the minimum cost of attracting equity capital. To provide some measure of financial flexibility, a financing flexibility allowance needs to be added to the ERP "bare-bones" cost. A financing flexibility allowance of no less than 50 basis points, which is equivalent to what the Commission has traditionally allowed, should be added to the ERP "bare-bones" result. The resulting return on book equity is 9.75-10.5%.

9. The DCF test, as applied to utilities, directly estimates their cost of equity. Conceptually, the test captures the totality of risks for which utilities' investors require compensation. As noted above, the discounted cash flow test estimates the expected return as the sum of the dividend yield plus investors' expectations of growth in the stock over the longer term.

I applied several DCF models to a sample of low risk utilities; the results of the various models indicate an expected equity return of 9.25%. Like the ERP test, the DCF test is a market-based test, which estimates a minimum cost of attracting capital. Thus, a financing flexibility allowance needs to be added to the DCF "bare-bones" cost. Adding a 50 basis point financing flexibility allowance, similar to that added to the ERP "bare-bones" cost, produces a return on book equity of 9.75%.

10. The comparable earnings test is the one test that measures returns in the same manner that the allowed utility return is set: on original cost book value. The comparable earnings test measures the rate of earnings of non-regulated (competitive) firms of similar risk to utilities. The comparable earnings test explicitly recognizes that Canadian utilities are not regulated on market value or current cost. They are allowed to earn returns on book value. Thus, a test that estimates returns measured on the same base as that to which the allowed return is applied is essential to the estimation of a fair return.

The comparable earnings test applied to a sample of low risk Canadian industrials indicates a fair return on book value for a benchmark low risk utility of no less than 13%.

11. The results of all three tests are summarized below:

	Fair Return On Equity
Equity Risk Premium Test	9.75-10.5%
Discounted Cash Flow Test	9.75%
Comparable Earnings Test	no less than 13.0%

In arriving at a recommended return on equity for a benchmark low risk utility, I gave primary weight to the cost of attracting capital tests. Significant weight should also be given to the comparable earnings test. Based on all three tests, a fair return for a benchmark utility is 10.5%.

12. In its 1999 decision, the Commission adopted an adjustment mechanism for ROE that increases the allowed ROE by 80% of the change in forecast long Canada yields when the long Canada yield is above 6.0%, but decreases it by 100% of the change when the yield is below 6.0%. The Commission stated that "failing to have a sliding scale within that range [above 6.0%] could produce inadequate returns for utilities and results in capital attraction difficulties."[1] Not only is there no empirical justification for the different scales above and below 6.0%, it is the reduction in allowed ROE by 100% of the reduction in long Canada yields below 6.0%, rather than the 80% sliding scale at higher (above 6.0%) levels of interest rates, that is more likely to result in inadequate returns and capital attraction difficulties.

[1] August 26, 1999 BCUC Decision, page 23.

I recommend that the Commission adopt a symmetric sliding scale mechanism that adjusts the allowed return by 75% of the change in forecast long Canada yields over the full range of interest rates to which the mechanism should apply (4% to 8%). A 75% sliding scale approximates the estimated relationship between the utility cost of equity and government bond yields. Moreover, it would place the British Columbia utilities on a more even playing field with their Canadian peers, many of which are subject to a 75% sliding scale formula.

II. DEFINITION OF A BENCHMARK UTILITY AND RETURN

A key objective of my testimony in this proceeding is to establish a benchmark return on equity. A benchmark return on equity is one that can be used as a point of departure (or "benchmark") for setting the allowed return on equity for each of the utilities that the Commission regulates. In its 1999 decision the Commission adopted the term "low-risk benchmark utility."

The benchmark return is derived from data for utilities across industries (electric, gas distribution and gas pipeline), as well as from data for non-utilities. It is based on no specific utility and hence reflects no specific business or financial risk characteristics. Thus, a "benchmark low risk utility" is a hypothetical construct. However, one objective measure of what constitutes a low risk utility would be its ability, on a stand-alone basis, to achieve debt ratings of A.

Designation of a debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. The determination of the applicability of a benchmark return to a particular utility needs to consider both business and financial risk. Stand-alone debt ratings of A are an indication that a utility, given its allowed capital structure, faces a similar level of total risk to the benchmark.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would generally be allowed lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return. If, however, the subject utility, in conjunction with its allowed capital structure, faces a higher or lower level of total risk than the benchmark, an increment to, or reduction from, the benchmark return on equity will be required.

The return for a benchmark low risk utility as has been set by the BCUC since 1994 is conceptually the same return as was adopted in 2004 by the Alberta Energy and Utilities Board (AEUB) and in 1995 by the National Energy Board (NEB) in their generic and multi-pipeline cost of capital decisions. In all three cases, the regulator, in effect, set the allowed return for a benchmark utility. While each of the three regulators came to somewhat different conclusions regarding the approach to setting the return, the values of the various inputs to establishing the return, and the appropriate level of the return, conceptually, they were all setting a "benchmark" return. The only difference was how the "benchmark" return was applied to each of the utilities in the three jurisdictions.

The NEB adopted a single allowed ROE when it established its automatic adjustment mechanism for a number of oil and gas pipelines in its 1995 Multi-Pipeline Cost of Capital Decision. Each individual pipeline was deemed a common equity ratio that was intended to compensate for its business risk relative to the other pipelines, so that the single "benchmark" return on equity could be applied across all of the pipelines. In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002 and 36% in 2005.

The same approach was recently adopted by the AEUB in Decision 2004-052 (July 2, 2004). In that decision, the AEUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common "benchmark" return on equity to be applied to each of the utilities under its jurisdiction. The AEUB's decision established allowed common equity ratios ranging from 33% for electric transmission to 43% for a relatively risky gas pipeline. In the middle of the business risk range were the major electricity and gas distributors with allowed common equity ratios of 37% and 38%, respectively.

In contrast to the NEB and AEUB approach, this Commission has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. The combination of capital structures and equity risk premiums is also the approach that has been taken in Ontario and Québec.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/AEUB approach as long as the combination of allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. Moreover, in light of the small size of several of the utilities regulated by the BCUC (who could not, no matter how high the allowed equity ratio, attain a debt rating of A on their debt), the combination of different capital structures and equity risk premiums is a reasonable approach.

III. TERASEN GAS AND TGVI vs. THE BENCHMARK UTILITY

As noted in Section II, the applicability of the benchmark low risk utility return to a particular utility is dependent on that utility's total risk relative to the benchmark. The total risk reflects both the utility's business risks (short- and long-term) and its financial risks, where the financial risks are a function of the allowed capital structure.

The allowed return on equity and allowed capital structure are interdependent. The benchmark low risk utility return cannot be applied to a specific utility unless the capital structure allowed by the regulator will equate the utility's total risk level to that of the benchmark.

TERASEN GAS

Since the Commission first introduced the concept of a benchmark utility in its June 1994 Return on Common Equity Decision, Terasen Gas, with an allowed common equity ratio of 33%, has been equated to the benchmark low risk utility. In my opinion, a 33% common equity ratio is too low for Terasen Gas to be considered to be equivalent in risk to the low risk benchmark utility.

In arriving at that conclusion, I considered a number of factors:

1. The business risk environment in which Terasen Gas operates has changed materially since the 33% equity ratio was adopted. The most significant change is the increasingly competitive environment in which Terasen Gas operates. In recent years, however, as the gap between the delivered costs of natural gas and electricity has narrowed, Terasen Gas increasingly finds itself competing for load in the residential and commercial markets.

2. A comparison of the inherent market demand/competitive risks of Terasen to other major gas distributors indicates that Terasen Gas' customer base is more concentrated in the industrial sector (50% of load) than ATCO Gas (which is largely residential and commercial), Enbridge Gas and Union Gas. The industrial base of Terasen Gas is also more concentrated than either Enbridge's or Union's; over 45% of Terasen's industrial load is attributable to a single industry, the pulp and paper industry.[2] Given the nature and size of its industrial base, Terasen Gas is inherently riskier than utilities with a more economically diverse and/or a less industrial-based customer profile. In addition, none of those three LDCs face major competitive threats from alternative energy sources in the residential and commercial sectors. Of all the major gas distributors in Canada, only Gaz Metro faces higher demand/competitive risks than Terasen Gas.

3. All of the major gas distributors, including Terasen Gas, have deferral accounts for the commodity cost of gas. Terasen Gas also has a rate stabilization account that mitigates earnings volatility arising from weather and customer usage in the short-term; that mechanism does not change the utility's longer-term business risk profile. Weather protection has become a relatively common feature of North American LDCs since Terasen Gas's 33.0% allowed equity ratio was set in 1994. To illustrate, in Section IV.C.4.b, I conducted an equity risk premium test using a sample of U.S. gas distribution utilities. All of the companies in the sample either has a weather-normalization account or has some form of weather protection. In Canada, both Gaz Metro and Newfoundland Power have weather-normalization accounts.

4. In my view, Terasen Gas' business risks are comparable to those of the major Alberta and Ontario gas distributors. The allowed common equity

[2] The load percentages are simply to provide a perspective on the comparative demand/competitive risks among the utilities. The percentage of the total gross margin from industrial load is generally materially lower than the proportion of the load itself due to the rate structure.

ratios for the other major gas distributors are in the range of 35% (Enbridge and Union) to 38.0-38.5% (ATCO Gas and Gaz Metro, respectively). Each of the four also has an allowed preferred share component, ranging from 3.1% (Enbridge) to 7.5% (Gaz Metro).

5. Reviewing the universe of Canadian utilities, other than a number of the NEB-regulated pipelines who still have allowed common equity ratios of 30-31%, the next lowest allowed common equity ratio is the 33% allowed for electric transmission utilities in Alberta. In my opinion, the business risks of Terasen Gas exceed those of electric transmission by a considerable margin. The allowed common equity ratio of TransCanada PipeLines and Nova Gas Transmission are 36% and 35%, respectively. I would judge that these two pipelines face no higher business risk than Terasen.

6. Terasen Gas' low common equity ratio, in conjunction with the low level of allowed returns at current interest rates, contributes to a relatively low level of financing flexibility. The low level of financing flexibility, as reflected in relatively low coverage ratios, also, to some extent, reflects the lack of other securities in the capital structure that would provide some equity support to the senior debt. In 1999, Terasen Gas' regulated capital structure contained 9.4% preferred shares, all of which have been redeemed. All of the other major gas distribution utilities have some preferred shares or preferred securities in their allowed or actual capital structures.

The need for a utility to be able to access capital markets under most circumstances at reasonable rates provides a further rationale for strengthening the capital structure. I note, in that context, that in the recent National Energy Board decision (RH-2-2004, April 2005), raising TransCanada PipeLines' allowed common equity ratio from 33% to 36%, the NEB suggested, in effect, that the increase in the allowed common equity ratio was a pro-active means of preventing the deterioration in the pipeline's debt ratings.[3]

7. Both Moody's and Standard & Poor's have pointed to Terasen Gas' low common equity ratios. Moody's (July 2004) called the relatively high leverage a "credit challenge". Standard & Poor's (December 2004) has referred to the "thin deemed equity layers" of Terasen Gas and Terasen Gas (Vancouver Island), stating that the "combination of low profitability and high leverage results in an overall financial profile that is weak."

8. Although ATCO Gas' 38% allowed common equity ratio is toward the upper end of the range of common equity ratios currently allowed for the major Canadian gas distribution utilities, DBRS considers the deemed ratios for the ATCO Utilities[4] to be relatively low.

9. S&P's debt ratio guidelines for a utility with a "3" business profile score and ratings of A and BBB are as follows:

Rating	Debt Ratio Guideline
A	50-55%
BBB	55-65%

The guidelines ranges suggest that a debt ratio of no higher than 55% is warranted for a debt rating in the A category. A 60% debt ratio places Terasen Gas in the middle of the range for a BBB debt rating.

10. In summary, a 35-40% common equity ratio would place Terasen Gas on an equal footing with its peers that face similar business risk. At an

[3] The NEB recognized that a deterioration of the pipeline's debt ratings into the BBB category could limit the number of investors willing to hold TCPL debt securities.
[4] The ATCO Utilities include ATCO Gas, ATCO Pipelines and ATCO Electric.

allowed common equity ratio in the range of 35-40%, the benchmark low risk return on equity would be applicable to Terasen Gas.

If, however, the allowed common equity ratio were to remain at 33%, an incremental equity risk premium would be required to account for the low common equity ratio (high financial risk). The difference between a 33% and 37.5% common equity ratio (mid-point of the 35-40% range) equates to an incremental equity risk premium of approximately 70 basis points. At a 33% allowed common equity ratio, Terasen Gas should be allowed an equity risk premium of 70 basis points above my recommended benchmark low risk utility return (See Schedule 29).

TGVI

TGVI is requesting that the Commission approve a 40% common equity ratio and a 75 basis point incremental equity risk premium relative to the benchmark low risk utility. In my opinion, this proposal reasonably compensates for TGVI's level of business risk.

1. TGVI is a relatively small greenfield utility (assets of approximately $550 million including the Revenue Deficiency Deferral Account (RDDA)), which has been operating for slightly less than 15 years. As a greenfield utility, its market is being built from the ground up. TGVI's rates have been structured to compete with alternative energy sources, and to induce potential customers to convert to natural gas. Until 2003, rates were set at a discount to competing fuels and were too low to recover TGVI's cost of service. As a result, TGVI had built up an accumulated revenue deficiency (RDDA) which peaked at approximately $88 million.

2. Since 2003 TGVI's rates have been based on a cost of service model, incorporating "soft caps" in the residential and commercial sectors,

designed to maintain the utility's competitiveness versus electricity or oil as appropriate to the rate class. Nevertheless, TGVI's residential and small commercial rates are higher (on an efficiency-adjusted basis) than electricity rates.

3. TGVI's ability to build its residential and small commercial market has been hampered by relatively high natural gas prices, low population density in its service area (which translates into relatively high unit costs) and very competitive electricity rates.

4. TGVI's load remains largely industrial (close to 70%), attributable to seven pulp and paper mills (the Joint Venture) and a cogeneration plant. The contract with the Joint Venture was amended, and extended into the fall of 2004 for an additional two years past the original renewal period to 2012. However, under the amended contract the firm demand was reduced by approximately 67% compared to the prior agreement. The contract with BC Hydro, which relates to the cogeneration facility, is currently on a year-to-year basis and expires October 31, 2005. A second planned gas fired generation facility at Duke Point on Vancouver Island, which was expected to have contributed significant additional revenues to TGVI's operation, was recently cancelled by BC Hydro.

5. TGVI faces greater supply risks than the typical LDC, due to its dependence on a single pipeline system that traverses rugged terrain, and comprises both underwater and marine crossings.

6. Revenues from BC Hydro, in conjunction with royalty payments pursuant to the Vancouver Island Natural Gas Pipeline Agreement (VINGPA), have allowed TGVI to reduce the RDDA to approximately $60 million at December 2004. Under VINGPA, TGVI receives royalty payments from

the Provincial Government that reduce the cost of the gas commodity, which, in turn, improves the margin available to recover delivery costs.

7. While TGVI has an opportunity to recover the remainder of the RDDA (at $60 million, about 10% of total assts), it has no assurance that it will be able to do so. While, at present, TGVI is being assisted by the VINGPA royalty payments, those payments will terminate at the end of 2011. After 2011, TGVI's customers will be required to absorb the full commodity cost of gas. Further, TGVI has $75 million in interest free senior government loans outstanding that currently are a credit to rate base; as they are repaid, the rate base will rise, creating higher capital costs. The ability of TGVI to mitigate the impact of rising costs on customer rates will partly depend on its ability to add new customers and thus reduce its unit delivery costs. However, the ability to add new customers (both through conversion and new construction) hinges in large part on the competitiveness of TGVI's rates versus electricity rates. Given the intensely competitive market in which TGVI operates, there is a material risk that it will be unable to fully recover its full investment in utility assets.

8. As a greenfield utility in a very price-competitive service area, TGVI faces higher business risks than any of the major mature gas distribution utilities (i.e., ATCO Gas, Enbridge Gas, Gaz Metro, Terasen Gas and Union Gas). TGVI is more comparable to the smaller mature LDCs (AltaGas Utilities, Gazifère Inc., and Natural Resource Gas) and the two greenfield LDCs in the Maritime Provinces (Enbridge Gas New Brunswick and Heritage Gas).

9. The allowed common equity ratios and incremental equity risk premiums for the small mature and greenfield LDCs are as follows:[5]

[5] Excludes Pacific Northern Gas due to open request related to capital structure and ROE.

Table 2

LDC	Allowed Common Equity Ratio	Incremental Risk Premium (basis points)
AltaGas Utilities	41%	0
Enbridge Gas New Brunswick	50%	320 [a/]
Gazifère Inc.	40%	40 [b/]
Heritage Gas	45%	330 [c/]
Natural Resource Gas	50%	0

a/ Allowed ROE of 13% set in June 2000 when the average allowed ROE for major Canadian utilities was approximately 9.8%.

b/ Relative to Gaz Metro.

c/ Allowed ROE of 13% set in February 2003 when the average allowed ROE for major Canadian utilities was approximately 9.7%.

10. I judge TGVI to face higher business risks than AltaGas Utilities and to be in the same business risk class as Gazifère Inc. and Natural Resource Gas. I view TGVI to be somewhat less risky than either of EGNB or Heritage Gas, due primarily to TGVI's larger customer base and the level of government support that it has received. However, all three are facing difficulties in building a market from the ground up. I also judge TGVI to face higher business risks than FortisBC, for which the BCUC recently allowed a 40% common equity ratio and a 40 basis point equity risk premium relative to the benchmark low risk utility.

11. In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return.

Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium proposed for TGVI is reasonable.

IV. FAIR RETURN ON EQUITY FOR A BENCHMARK UTILITY

A. OVERVIEW OF APPROACH TO ESTIMATING THE BENCHMARK RETURN

To ensure that the allowed benchmark return considers all of the relevant factors that bear on a fair return, I recommend application of the three tests that have traditionally been used to set a fair return for regulated companies: the equity risk premium test, the discounted cash flow test and the comparable earnings test. Reliance on multiple tests recognizes that no one test produces a definitive estimate of the fair return.[6] Each test is a forward-looking estimate of investors' equity return requirements. However, the premises of each of the three tests differ; each test has its own strengths and weaknesses. In principle, the concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unreasonable to view it as such.

A fair return is one that provides a utility with the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

These criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. The two standards are applied using different tests. The equity risk premium and discounted cash flow tests establish the cost of attracting capital. The comparable earnings test is a measure of the comparable return, or comparable earnings, standard. A fair and

[6] As stated in Bonbright, "No single or group test or technique is conclusive." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, Va.: Public Utilities Reports, Inc., March 1988).

reasonable return gives weight to both the cost of attracting capital standard and comparable earnings standard.

In its 1999 decision, the Commission concluded that the distinction drawn between the capital attraction standard and the comparable earnings standard was artificial, that is, if a utility could attract capital, by definition, the comparable earnings standard was met. I disagree with this conclusion. Virtually any company can attract capital, at a cost. The ability to attract capital is not synonymous with being allowed a return comparable with those of similar risk entities. A return that simply allows a utility to attract capital, irrespective of the cost, does not lead to the conclusion that it is compatible with the comparable returns standard.

The fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction and comparable earnings standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, the courts opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination.[7] The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment.

[7] *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)).

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. Historic costs have been substituted for marginal or incremental costs for two reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets.

The current cost of attracting capital is measured by reference to market values. The discounted cash flow test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms).

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services; raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

Therefore, when the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value.

B. PERSPECTIVE ON CURRENT APPROACH TO SETTING ALLOWED RETURN ON EQUITY

1. The Allowed Return on Equity before Automatic Adjustment Mechanisms

A review of the history of the approach to setting the allowed return in Canada reveals that, prior to the widespread adoption of automatic adjustment mechanisms, regulators routinely gave weight to the results of various tests. The three tests, as previously indicated, are the equity risk premium, discounted cash flow and comparable earnings tests. A brief description of each test follows.[8]

The equity risk premium test is a generic term for a methodology that estimates the cost of equity as the sum of a directly observable yield on a security such as a government or corporate bond and a premium to compensate for the additional equity risk assumed by the investor. Canadian regulators have typically applied the equity risk premium test using a long-term Government of Canada bond yield as the point of departure. To that yield is added an equity risk premium reflecting compensation for the additional risk of investing in a regulated utility.

The discounted cash flow test measures the equity investors' expected return as the dividend yield on a stock or group of stocks plus the expected growth in dividends in the long-term.

The comparable earnings test measures the expected returns on book equity of firms that are of similar risk to the utility for which the regulator is setting the fair return.

[8] A more detailed description is provided with the application of each test.

In giving weight to multiple tests, some regulators explicitly recognized the distinction between the capital attraction standard and the comparable earnings standard. To illustrate, the Public Utilities Board of Alberta, in Decision E91093 (December 1991), recognized the difference between original cost and market value, and the resulting relevance of comparable earnings:

> "The Board recognizes that, in the competitive world, pricing and investment decisions are based on the current market values of assets and the current cost of new capital. However, because the investment base for regulatory purposes is stated on original cost book values, a rate of return such as that determined under the comparable earnings test becomes meaningful." (p. 195).

Other Canadian regulators either explicitly or implicitly gave weight to all three tests in setting the allowed return. Some examples include:

In its August 1992 *Reasons for Decision* for Westcoast Energy, the National Energy Board stated that it relied on all three methods used for assessing a fair and reasonable return.

In EBRO 485 (December 1993) for Consumers Gas, the Ontario Energy Board stated that it had taken account of the different results of all the tests.

In the mid-1990s, however, Canadian regulators began to shift from giving weight to multiple tests to virtual sole reliance on a single test, namely the equity risk premium test. In 1994-1995, the BCUC and the NEB began seeking to streamline the process of setting allowed returns, given the time (and cost) required to revisit the fair return issue on an annual basis. The BCUC initially adopted its automatic adjustment mechanism based on the equity risk premium test in April 1994; the NEB adopted a similar approach in early 1995. Their choice of the equity risk premium test reflects in part the fact that its point of departure – the 30-year Canada yield – is observable and objective. Their focus on the equity risk premium test, to the exclusion of other tests, appears to be largely a function of the economic and capital market conditions prevailing at the time.

2. Economic and Capital Markets in 1994-1995

In 1994-1995, the Canadian economy and capital markets were in the relatively early stages of significant structural changes. These changes had their genesis earlier in the decade with the Federal Government's commitment to low inflation and fiscal restraint. However, the Federal Government had yet to make significant headway in debt reduction; Canada's net debt/GDP ratio reached its peak (over 68%) in 1996. "Nominal" (or alternatively, conventional)[9] long-term Canada bond yields, which averaged approximately 8.6% during 1994-1995, reflected a high real cost of capital due to both concerns with Canada's fiscal condition and a strained relationship with Québec.

a. Inflation Fears and Bond Yields

While inflation had declined dramatically, from an average of 4.7% in 1983-1991 to 1.2% during 1992-1994 (Schedule 7), there remained substantial concern that it would reignite. During 1994-1995 long-term inflation-indexed Government of Canada bonds yielded 4.6% on average, compared to the 8.6% yield on the "nominal" 30-year Canada bonds, a differential of 4.0 percentage points (or 400 basis points) (Schedule 7).

The differential between nominally denominated bonds and inflation-indexed bonds represents the compensation investors in the former require for inflation protection. In 1994-1995, economists were forecasting long-term inflation of only 2.2%[10] well below the 4.0 percentage point average difference between "nominal" and inflation-indexed bonds. The difference of 1.8% (4.0% - 2.2%) is

[9] As contrasted with real return, or inflation-indexed, bonds.
[10] Consensus Economics, *Consensus Forecasts*, April and October of 1994 and 1995.

an estimate of the additional premium required at the time by holders of the conventional bonds to assume the risk that actual inflation would exceed the forecast level. The material difference observed indicates that bond investors perceived conventional bonds to comprise a relatively high level of risk.

b. Equity Markets

In the equity markets, the TSE 300 had just completed five years of mediocre performance (5.6% and 4.5% annual arithmetic and geometric returns respectively for 1990-1994, compared to 9.3% and 9.0% for the S&P 500). Over the same period, returns on conventional long-term Government of Canada bonds outpaced the equity market returns by a significant margin. The average bond returns during 1990-1994 were 10.7% and 9.9% on an arithmetic and geometric basis respectively. The experience of 1990-1994 alone had squeezed the post-World War II achieved Canadian equity risk premiums by 1.3 percentage points; the historic equity risk premium declined from a 1947-1989 arithmetic average of 7.6% to a 1947-1994 average of 6.3%.[11]

c. Early Stages of Market Globalization

In the mid-1990s, Canadian regulators determined the equity market risk premium primarily on the basis of historic Canadian data. The trend toward globalization of capital markets had been raised as an issue, but the shift from largely domestic investments to a mix of domestic/foreign investments was evolutionary, and largely overlooked in cost of capital determinations. Despite the increasing exposure of Canadian investors to foreign equity markets,[12] the returns available

[11] The corresponding reduction in the achieved market risk premium on a geometric average basis was from 6.3% to 5.5%.

[12] The Investment Funds Institute of Canada (IFIC) reported in its "Year 2000 in Review" report of mutual fund industry statistics that the proportion of all Canadian mutual fund assets including money market assets, but excluding the foreign portion of balanced funds, invested in foreign securities was approximately 17% in 1990; in late 1994 that proportion had increased to 29%.

from those markets – particularly from the broader U.S. market – were given little or no weight in the assessment of the equity market risk premium.

d. Corporate Profitability

The outlook for Canadian industrial returns was uncertain. The country had endured a protracted period of recession and restructuring (1990-1994);[13] resulting largely from the combined efforts of the Government to stem inflation and of industry to respond to the prospects of free trade. With the dramatic break in inflation, and the impact of recession and restructuring, the earned returns of Canadian industrials had fallen well below levels experienced during the 1980s.

3. Impact of Market Conditions on Determination of the Allowed Return

The evolving economic/capital market climate raised concerns regarding the reliability of the data underpinning various cost of equity tests. The application of the comparable earnings test had become problematic. Two factors were key to the reliability of the comparable earnings test in the mid-1990s:

1. The sharp decline in inflation in 1992 cast considerable doubt on the relevance of pre-1991 returns on equity – earned during an environment of significantly higher inflation – to a future business cycle.

2. The returns achieved during 1990-1994 reflected the impact of a prolonged recession and restructuring period; the ability of Canadian industry to restructure successfully was not assured.

Related factors reduced the reliability of the discounted cash flow test, which had typically been applied to low risk industrial firms. The discounted cash flow

[13] Average GDP growth from 1990-1994 was only 1.2%; see Schedule 6.

model requires estimates of investor expectations of future growth in conjunction with prevailing dividend yields. With the protracted decline in earnings, and concurrent lack of growth (or, in some cases, reductions) in dividends, historic growth rates for industrial firms provided no insight into investor expectations for future growth rates. Further, direct measures of investor growth expectations for publicly-traded Canadian firms (e.g., consensus forecasts of long-term growth rates), were not widely available. Thus, the DCF model could not be reliably applied.

The equity risk premium test was effectively the only remaining choice, despite its own shortcomings, e.g., the unreliability of beta as a measure of relative risk (as recognized by the BCUC in the 1999 decision). As a result, its initial adoption by Canadian regulators as virtually the sole basis for setting a benchmark return and for designing an automatic adjustment mechanism was not unreasonable. The equity risk premium test provided an objective (observable) means of not only establishing a point of departure, i.e., the long Canada yield, but also for estimating subsequent changes in the equity return requirement.

The adoption of the equity risk premium test by the BCUC and the NEB was relatively quickly followed by the Ontario Energy Board (1997), the Régie de Gaz (1998), the Public Utilities Board of Newfoundland and Labrador (1998) and the Alberta Energy and Utilities Board (1997).[14] As more regulatory boards adopted a similar approach, each regulator could be relatively confident that the returns of utilities under its jurisdiction would not deviate significantly from those adopted elsewhere in the country.

[14] Although the AEUB did not adopt an automatic adjustment mechanism based on the risk premium test until 2004, it has been using the equity risk premium test virtually exclusively since 1997 (U97065).

4. Key Factors Determining the Level of Allowed Risk Premiums in the Mid-1990s

Since many Canadian utilities are subject to automatic adjustment formulas that have their genesis, explicitly or implicitly, in the mid-1990s, it is worth summarizing the key factors that may explain the level of equity risk premiums that underlie the initial returns allowed by Canadian regulators in establishing automatic adjustment mechanisms in the 1990s.

1. The additional premium in nominal Government of Canada bonds, reflecting the fear that actions of the Federal Government would reignite inflation (often referred to as the "lock-in premium"). The additional premium required by holders of conventional long-term government bonds exceeded that required by equity holders. This is because equities are viewed by investors as a superior hedge against inflation. Thus, the higher "lock-in" premium in government bonds resulted in a contraction in the required equity market risk premium.

2. The mediocre performance of the TSE 300 in the early years of the 1990s helped squeeze the achieved Canadian equity risk premiums; the decline in the achieved equity market returns may have been interpreted as a reduction in the required (forward looking) equity market risk premium.

3. As the transition to a global capital market had yet to be fully appreciated, the determination of the benchmark returns gave little recognition to the alternative investment opportunities outside the Canadian market. Giving weight to the U.S. equity risk premium would have led to higher allowed utility equity risk premiums.

4. The mediocre performance of the overall Canadian equity market relative to that of utilities may have been perceived as an indication that utility investors were being overcompensated.

5. <u>Changes in Economic and Capital Markets Since the Mid-1990s</u>

a. <u>Government Bond Market</u>

Subsequent to the initial adoption of automatic adjustment formulas by the BCUC and the NEB, long Canada bond market conditions began to change dramatically. By 1997, the Federal Government's commitment to containing inflation, by reducing budget deficits and debt levels, began to bear fruit. Interest rates began to decline rapidly in Canada. At the end of 1996, the spread between 30-year Canadas and 30-year U.S. Treasuries – which had been 200 basis points at the beginning of the decade – was only 40 basis points. By mid-1998, the real yields on "nominal" long Canada bonds had declined significantly, as bond investors' fear of inflation abated, to the point where they no longer comprised a "lock-in premium" for unanticipated inflation.[15] The disappearance of the "lock-in premium" was an indication that the perceived riskiness of long Canada bonds had declined. The disappearance of the "lock-in premium" in bond yields unmatched by a change in the perceived riskiness of the equity market translated into a higher equity market risk premium.

In August 1998, the global market crisis that had begun in 1997 came to a head.[16] The crisis sent investors scurrying into safer government securities, precipitating an upward shift in the spreads between utility and government bond yields.

[15] With nominal 30-year Canadas yielding 5.6% in July 1998 and inflation-indexed bonds yielding 3.87%, the differential of 1.7% was slightly less than the consensus forecast of long-term inflation of 1.9% (Consensus Economics, *Consensus Forecasts*, April 1998).

[16] The crisis had been triggered by a recession in Southeast Asia and a fall in commodity prices worldwide. This, in turn, precipitated a collapse in the Russian economy. The crisis then spread to Latin America as investors began liquidating riskier securities and scrambling into safe havens, primarily U.S. Treasury bonds.

The upward shift in utility/government bond spreads can also be traced in part to the improving finances of the Canadian government. In fiscal year 1997-1998, the Federal Government achieved its first budget surplus since 1973.[17] With the budget deficit eliminated, the market anticipated a reduction in long-term government financing. The expectation of a reduced supply of long-term bonds put downward pressure on long-term government bonds yields. The result was a scarcity premium, which was clearly observable from early 2000 through early 2002.[18] When long Canada bond yields reflect a scarcity premium (bond prices are artificially high and yields artificially low), their use in the equity risk premium test, without proper adjustment, will understate the cost of equity.

The Federal Government recognizes the importance of long-term government bonds to investors, particularly institutions such as insurance companies that attempt to match the duration of their assets and liabilities. Consequently, the government has undertaken to maintain a liquid market for 30-year Canadas. Since 2002, the presence of a scarcity premium has not been detectible, as evidenced by a historically normal spread between 10- and 30-year Canadas. Nevertheless, as the Federal Government has continued to post budget surpluses, its external financing requirements have continued to decline. A declining stock of outstanding long-term government bonds makes it more difficult to maintain a liquid market for those bonds, and puts downward pressure on long Canada bond yields.

b. Utility Bond Market

In the utility bond market, the higher spreads that emerged with the global market crisis and the flight to quality persisted even after the 1998 crisis passed. Multiple factors acted to keep spreads high, including the scarcity premium in government

[17] The first surplus has since been followed up with six consecutive surpluses.
[18] The scarcity premium was evidenced by minimal to negative spreads at the long end of the yield curve (10- and 30-year), when the rest of the yield curve was generally upward sloping.

bond yields discussed above and, later, a crisis of confidence in corporate America, as well as a soft global economy.

To put the change in spreads in perspective, the spread between long-term Canadian A-rated utility bonds and 30-year Canadas averaged only 60 basis points from 1996-August 1998, despite the significant financing requirements of the Federal and Provincial Governments. (High government financing requirements tend to crowd out issues of private businesses, raising spreads for private issuers.) Those spreads widened materially subsequent to the August 1998 crisis, peaking in late 2002 at close to 190 basis points. With the rebound of the economy from the 2001 downturn, spreads have since tightened. Nevertheless, the recent spread for long-term (30-year) A rated utility issues remains relatively high (approximately 120 basis points), when viewed in light of the reduced financing needs of the Federal and Provincial Governments and the overall receptiveness of the bond market to new utility issues at the present time. The comparatively high spreads point to a perception by investors of an increased level of utility risk.

c. Relevance of Changes in Debt Markets to Allowed ROEs

With the benefit of the experience in the debt markets since 1994-1995, at least four factors have emerged that are relevant to allowed ROEs that are determined solely by reference to the equity risk premium test, or which have their origins in the mid-1990s by virtue of an automatic adjustment mechanism.

1. The world market events of August 1998 brought into focus the globalization of markets and the ability of investors to seamlessly redeploy vast amounts of capital across borders. The global integration of capital markets requires explicit recognition of alternative investment opportunities beyond domestic boundaries.

2. The scarcity premium reflected in artificially low long-term government bond yields due to an anticipated decline in supply reduced the allowed returns for Canadian utilities for reasons unrelated to the equity cost of capital. Sole reliance on a cost of equity methodology that tracks long-term government bond yields raises the risk that the true cost of equity will be underestimated.

3. Utility stocks are interest sensitive. Since a utility's cost of debt, like its cost of equity, is determined by its business and financial risks, it should be expected that the utility cost of equity will track the utility cost of debt,[19] all other things equal, more closely than it will track the Government of Canada bond yield. Trends in the cost of capital to utilities, which are reflected in their cost of debt, are not directly captured by an equity risk premium model tied to government bond yields.

4. Stated more generally, with sole reliance on the equity risk premium test, the allowed ROE closely tracks changes in government bond yields, to the virtual exclusion of other factors that bear on a fair return on equity for a utility.

d. <u>Equity Markets</u>

i. Globalization

There are also factors specific to the equity markets that need to be considered in evaluating the levels of allowed returns in Canada. Of key importance is the recognition that Canadian investment opportunities are not limited to domestic

[19] The spread between corporate bond yields and government bond yields is frequently utilized in academic studies as a means of tracking changes in investors' relative risk perceptions and the risk premium. Two examples include: Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", *Journal of Applied Finance*, Volume 11, No. 1, 2001; and R. Jagannathan and Z. Wang, "The Conditional CAPM and the Cross-Section of Expected Returns", *Journal of Finance*, 1996.

investments. The risk premium analysis should recognize the increasing globalization of capital markets and the increasing proportion of Canadians' investments in foreign equity securities (particularly U.S. securities).

In the latter half of the 1990s, Canadian investors became increasingly aware of the mediocre performance of the Canadian equity market, and, given the relatively small size of that market relative to the total global market (approximately 2%), pressure mounted to increase the cap on foreign investments held in RRSPs and pension funds.[20] The 2000 Federal Budget introduced an increase to 30% from the then prevailing 20% by 2001. The most recent budget (delivered February 23, 2005) removed the cap entirely.[21]

Investment outside of Canada has continued to grow rapidly as the barriers to foreign investment (in terms of both transactions and information costs as well as the foreign investment cap) have continued to decline. Foreign stock purchases by Canadians have more than quadrupled since 1995. Purchases in 1995 were \$83 billion; in 2004, they were \$513 billion.[22] In 2004, although the total percentage of foreign assets in the top 100 Canadian pension funds was only approximately 29%, the percentage of foreign equity to total equity was over

[20] The Investment Funds Institute of Canada (IFIC) had estimated in 1999 that raising the cap to 20% would increase returns by 1% and raising the cap to 30% would increase the returns by another 0.5%. "Paving the Way for Change to RRSP Foreign Content Rules", Tom Hockin, President and CEO IFIC, January 31, 2000.

[21] The Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) had commissioned a report entitled "The Foreign Property Rule: A Cost-Benefit Analysis" (David Burgess and Joel Fried, University of Western Ontario, November 2002), which supported the removal of the cap. *The Globe and Mail* reported that the removal of the foreign content cap is expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value." Rob Carrick, "Finance: Your Bottom Line", Globe and Mail.com, February 23, 2005.

[22] The IFIC's report "Year 2002 in Review" stated,

> "During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds."

50%.[23] In other words, pension funds have concentrated their foreign investment allocations to the equity markets, with the preponderance of their fixed income allocations in domestic bonds.

ii. Characteristics of Historic Canadian Equity Market

A second key consideration is that there are factors specific to the historic Canadian returns that cast doubt on the premise that the achieved returns are likely to be a good proxy for investors' future expected returns. One factor is the cap on foreign investment that historically has, to some extent, held investment captive in Canada. A second factor is the structural change of the Canadian equity market over the periods typically used to measure historic risk premiums. Although this structural change has occurred gradually, the current make-up of the S&P/TSX Composite, as shown in Table 3 below, is materially different than it was 25 years ago.

The historic Canadian risk premiums reflect in considerable measure a resource-based economy. At the end of 1980, no less than 46% of the market value of the TSE 300 was resource-based stocks.[24] By comparison, over the past two years, the resource-based percentage of the S&P/TSX Composite averaged just over 30%.[25] As the resource sectors have declined in importance, the influence of technology-intensive sectors on the index has risen markedly. Table 3, which compares the year-end 1980 and 2005 (Q1) market weightings of the technology/service sectors, highlights the change over the past 25 years. Investor returns expected from an equity market characterized by technology-intensive stocks may be quite different from returns expected from a market dominated by resource-based stocks.

[23] Benefits Canada, "Pensions without Borders", May 2005.
[24] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.
[25] Energy and Materials Industry Sectors; the weight of these sectors has recently increased reflecting the run-up in energy prices over the past 12 months.

Table 3

	1980	**2005**
Biotechnology/ Pharmaceuticals/ Health Care	0.0%	1.5%
Information Technology	0.9%	5.9%
Telecommunication Services	4.8%	5.3%
Media & Entertainment	0.6%	3.3%
Financial Services	13.5%	32.2%
	19.8%	48.2%

Source: *TSE Review*, December 1980 and March 2005.

Despite the shift in the make-up of the S&P/TSX Composite, the Canadian market remains significantly less diversified than the U.S. market. There are various sectors of a diversified economy that are relatively underrepresented in the Canadian equity market, e.g., pharmaceuticals, retailing and health care.

The average achieved returns on the TSE 300 Index were significantly affected by the relatively poor performance historically of commodity-based equities. Over the 1956-2003 period (the longest period for which consistent data exist for the individual TSE 300 sub-indices), the average returns of the commodity-based sectors were exceeded by the returns of virtually every other sector of the TSE 300.[26] Because the long-term returns of the various sectors are inconsistent with their relative risk, the achieved risk premiums may not accurately reflect what investors had expected.

[26] The average (compound, or geometric) returns of the commodity-based sectors were as follows:

Metals/Minerals	7.8%
Gold	9.5%
Oil and Gas	9.5%
Paper/Forest	7.1%

By comparison, the corresponding simple average of the remaining sectors' returns over the same period was 10.3%.

Third, a further impediment to reliance on the Canadian market as the "market portfolio" has been the undue influence of a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value and BCE's disposal of its 35% interest in Nortel, Nortel and BCE shares alone accounted for 35% of the total market value of the TSE 300. To put this in perspective, the largest two stocks in the S&P 500 at the same time accounted for only 8% of its total market value. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the TSE 300 regarding the forward-looking market risk premium.

Further, the Canadian equity market, which historically was proxied by the TSE 300 (1956-2001), has also been criticized for its lack of liquidity. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> "Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An amply supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index."

When the TSE 300 was overhauled (becoming the S&P/TSX Composite in May 2002), 275 companies were initially included, instead of the previous 300.[27] At March 31, 2005 there were only 226 companies in the Composite.

In mid-2005, the S&P/TSX Composite will be materially changed once again with the inclusion of income trusts. Income trusts, which just five years ago, had a market capitalization of approximately $20 billion, now have a market capitalization of approximately $130 billion, accounting for over 10% of the total market value of the publicly traded equities in Canada. Income trusts have significantly outperformed the "conventional" equity markets during the period for which income trust market data are readily available. The annual total return for the S&P/TSX Capped Income Trust Index over the 1998-2004 period averaged 17.4%, compared to 6.4% for the S&P/TSX Composite Index. The exclusion of income trust returns from the S&P/TSX Composite Index to date means that the measured equity returns understate the actual equity market returns achieved by Canadian investors.

iii. Relevance of U.S. Risk Premium Data

Finally, from 1947-2004, the achieved risk premiums in Canada were 170-180 basis points lower than in the U.S. Of that amount approximately 70 basis points is accounted for by historically higher bond yields in Canada. With the vastly improved economic fundamentals in Canada (particularly the fiscal health), the risk of investing in Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bonds that existed historically, on average, is not expected to persist in the future. The most recent consensus long-term forecasts anticipate 10-year bond yields to be slightly lower in Canada than in the U.S. in the future. The most recent long-term forecasts from Consensus Economics anticipate an average yield of 5.5% from 2006-2015

[27] The overhaul of the composite index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index.

for Canada and 5.6% for the U.S. (Consensus Economics, *Consensus Forecasts,* April 2005). With similar interest rates in the two countries, the differential between equity and bond returns should, *ceteris paribus*, be closer in the future than it was historically. Consequently, the U.S. historic equity market risk premium should be considered to estimate the forward-looking equity market risk premium for Canadian investors.

In contrast to the S&P/TSX Composite, the historic U.S. equity returns were generated by a more diversified and liquid market. In addition, the U.S. equity market has historically been the principal alternative to domestic equity investments. The diversified nature of the U.S. equity market, as well as the close relationship between the Canadian and U.S. capital markets and economies, warrant giving significant weight to U.S. historical equity risk premiums in the estimation of the required equity risk premium applicable to Canada. Recognition of the relevance of U.S. market data in estimating the allowed return results in a higher estimate of the equity market risk premium, and in turn, of the equity return requirement for a benchmark utility.

6. Indicators of Inadequate Allowed Returns for Canadian Utilities

There are a number of indications that the strict reliance on equity risk premium models in conjunction with automatic adjustment formulas has resulted in allowed returns for Canadian utilities generally that are too low. These include the achieved returns of low risk (comparable) industrials, allowed returns of U.S. utilities, and concerns expressed by capital market participants.

a. Returns of Low Risk Industrials

The returns of comparable (low) risk industrials indicate an increasing divergence between Canadian utility and industrial returns. The comparable earnings test, discussed later in detail, shows that low risk Canadian industrial returns have averaged approximately 13.0-13.5% over a full business cycle (1993-2004); they can be expected to remain at or above that level going forward. At 13.0-13.5%, the low risk Canadian industrial returns are some 375 basis points higher than the returns allowed by Canadian regulators for 2005 (13.25% versus 9.5%).

b. Allowed Returns for U.S. Utilities

With respect to allowed returns, the following table compares the allowed returns for Canadian utilities to those allowed for U.S. utilities (electric and gas) since 1994.

Table 4

Year	Average Allowed ROE: Canadian Utilities	Average 30-Year Canada Yield	Risk Premium	Average Allowed ROE: U.S. Utilities	Average 30-Year/ Long-Term Treasury Yield	Risk Premium
1994	11.5%	8.7%	2.9%	11.3%	7.4%	4.0%
1995	12.1	8.4	3.7	11.5	6.8	4.7
1996	11.4	7.8	3.6	11.3	6.7	4.6
1997	10.9	6.7	4.2	11.3	6.6	4.8
1998	10.2	5.6	4.6	11.6	5.5	6.0
1999	9.5	5.7	3.8	10.7	5.9	4.8
2000	9.8	5.7	4.1	11.4	5.9	5.5
2001	9.7	5.8	3.9	11.0	5.5	5.5
2002	9.6	5.7	3.9	11.1	5.4	5.7
2003	9.7	5.3	4.4	11.0	5.0	6.0
2004	9.6	5.1	4.5	10.7	5.1	5.6
2005 Q1	9.5	4.7	4.8	10.5	4.7	5.8

Source: Schedule 5.

Table 4 above shows that Canadian allowed utility returns were at similar levels to U.S. utility returns between 1994-1997. However, while allowed Canadian returns have declined by approximately 200 basis points from 11.5% to 9.5%, the decline in U.S. allowed returns has been more moderate (from about 11.5% to 10.5%).

Given the similarity in the cost of capital environment between Canada and the U.S., it should be expected that the allowed returns in the two countries should, given a similar utility risk environment, have converged. However, as Canadian regulators gravitated toward the equity risk premium test in the mid-1990s, Canadian allowed returns on equity tracked the downward trend in government bond yields to a much closer degree than allowed returns in the U.S. Currently the differential between allowed returns in Canada and the U.S. is about 100 basis points.

Differences in risk do not explain the differences in the level of allowed returns. When the focus is on a comparison of relatively "pure-play" utilities, the debt rating agencies do not view Canadian utilities as facing a materially different level of business risks than their U.S. counterparts. To illustrate, the typical business profile score assigned by S&P to both U.S. gas LDCs and combination electric/gas transmission/distribution utilities rated A- or better is currently "3"[28] (Schedule 4). The typical scores that were assigned to Canadian utilities (electric, gas LDC and gas pipelines), most of which have debt rated in the A category, was also "3".

[28] On a scale of "1" to "10", with "1" being the lowest business risk. The average score of all U.S. regulated companies, including those with significant unregulated operations, is "5".

The scores that were assigned by S&P to major Canadian utilities are as follows:

Table 5

Company	S&P Business Risk Profile
AltaLink L.P.	2.5
CU Inc.	3
Enbridge [1/]	2
Hydro One Inc.	3
Newfoundland Power	3
Nova Gas Transmission	3
Nova Scotia Power	4
Terasen Inc./Terasen Gas	3
TransCanada PipeLines	3
Median	**3**

[1/] Enbridge Inc. and Enbridge Gas Distribution.

Thus, S&P's business risk analysis has placed the typical Canadian utility in a similar business risk category to a typical U.S. gas distribution utility or transmission/distribution electric utility with a debt rating of A- or better.

The possibility that gas and electric utilities in the U.S. face higher business/regulatory risks than the typical Canadian utility is offset by significantly higher allowed common equity ratios in the U.S. The average allowed common equity ratio for the major investor-owned Canadian gas and electric utilities is approximately 37%. In contrast, the average allowed common equity ratio for U.S. gas and electric utilities (2000-2005 Q1) has been approximately 47%, as shown below in Table 6.

Table 6

Allowed Common Equity Ratios for U.S. Gas and Electric Utilities	
2000	48.7%
2001	46.3%
2002	47.2%
2003	49.7%
2004	46.3%
2005 (Q1)	45.3%
Average [1/]	47.2%

1/ Weighted by number of decisions in each year.

Source: Regulatory Research Associates, *Major Rate Case Decisions, January 2003-December 2004,* January 2005 and *Major Rate Case Decisions – January to March 2005*, April 2005.

The difference in equity ratios between Canadian and U.S. utilities can be quantified, that is, translated into a further differential in equity returns. The ten percentage point differential between the average common equity ratios for the U.S. and Canadian utilities translates into approximately 100 basis points in equity return compensation in favor of U.S. utilities.[29]

c. Concerns of Capital Market Participants

There have been, over the past several years, concerns expressed by market participants regarding the disparity between allowed returns in Canada and the U.S. The Dominion Bond Rating Service (DBRS) has pointed to the low level of Canadian allowed returns. In a May 2003 commentary entitled, "The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities Have Lower Ratios, and Five Changes to Regulation Which Should Be

29 Using approaches outlined in Schedule 29.

Introduced in Canada" (May 2003), DBRS called for increasing the allowed returns in Canada in order to make them more consistent with U.S. returns.

The allowed return for utilities in British Columbia has been lower than elsewhere in Canada in recent years. For Terasen Gas, DBRS considers "low allowed ROEs versus Canadian peers" to be a "Challenge" (DBRS, Terasen Gas Inc., June 21, 2005).

In December 2004, subsequent to the EUB's Decision 2004-052, DBRS referred to the low approved returns on equity as a "Challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated:

> "While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta."

Additional recent DBRS reports citing the challenge of low approved returns on equity have been published for other Alberta utilities, i.e., AltaLink (November 2004), and FortisAlberta (September 2004).

Standard & Poor's, in its recent summary report on Terasen Gas Inc. (April 18, 2005), stated,

> "The regulation, however, is considered weak in comparison with international peers with regard to the allowed returns on equity (9.03% for Terasen Gas and 9.53% for TGVI for 2005) and thin deemed equity layers (33% for Terasen Gas and 35% for TGVI, respectively)."

Standard & Poor's has also cited the Alberta utilities' low equity returns and common equity ratios subsequent to the Generic Cost of Capital decision. In its recent report for AltaLink, S&P stated,

> "Like many Canadian regulated utilities, AltaLink's modest financial position is constrained by a comparatively low approved ROE and thin equity base." (S&P, AltaLink, April 19, 2005).

A CIBC World Markets Report entitled "Pipelines and Utilities: Time to Lighten Up", published December 2001, stated, in reference to the-then recent formulaic reduction in Newfoundland Power's allowed return:

> "The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S."

In her August 15, 2003 "Research Industry Comment: Utilities", entitled "It's the Grid, Silly" (following the power outage in Canada and the U.S.), RBC Capital Markets' analyst Maureen Howe pointed to the relatively low level of Canadian utility returns. In her "Investment Opinion", she stated,

> "Allowed returns on equity (ROEs) in Canada for regulated transmission and distribution utilities are relatively low compared to the U.S. For example, the Alberta Energy and Utilities Board recently approved an allowed ROE of 9.4% based on a 34% deemed common equity component for AltaLink. In comparison, the U.S. Federal Energy Regulatory Commission (FERC) approved an allowed ROE of 13.88% for International Transmission Co., which took over DTE Energy's transmission assets in April 2003. To encourage new transmission investment, FERC has proposed additional incentives that would boost allowed ROEs for transmission investments. With renewed emphasis on new investment in the power grid, Canadian regulators could follow suit."

7. Conclusions

The factors discussed above indicate:

1. The prevailing ROEs for Canadian utilities, generally, are too low. The benchmark low risk utility ROE in British Columbia, in turn, is approximately 45 basis points lower than the allowed ROEs set by other regulators that may also be characterized as benchmark returns.[30]

   The generally low allowed ROEs in Canada make Canadian utilities relatively unattractive investments versus their U.S. peers. In turn, the lower allowed ROEs in British Columbia penalize that province's utilities relative to their Canadian peers. As indicated in the following table, the British Columbia utilities' risk compensation (the weighted equity return component of the allowed return on rate base) has been materially lower than their peers.

[30] AEUB, NEB, OEB, La Régie and Newfoundland and Labrador Public Utilities Board (See Schedule 5).

Table 7

	Allowed Common Equity Ratio (1)	Allowed Return at Forecast 5.25% Long Canada (2)	Weighted Equity Return Component (Col 1 x Col 2)
Terasen Gas	**33.0%**	**8.75%**	**2.89%**
Comparables			
ATCO Gas	38.0%	9.28%	3.52%
Enbridge Gas	35.0%	9.15%	3.20%
Gaz Metro	38.5%	9.28%	3.57%
TransCanada Pipelines	36.0%	9.24%	3.33%
Union Gas	35.0%	9.30%	3.25%
AVERAGE	36.5%	9.25%	3.38%
TGVI	**35.0%**	**9.25%**	**3.24%**
Comparables			
AltaGas Utilities	41.0%	9.28%	3.80%
EGNB	50.0%	13.00%	6.50%
Gazifère	40.0%	9.68%	3.87%
Heritage	45.0%	13.00%	5.85%
Natural Resource Gas	40.0%	9.15%	3.66%
AVERAGE	43.2%	10.82%	4.74%
FortisBC	**40.0%**	**9.15%**	**3.66%**
Comparables			
AltaGas Utilities	41.0%	9.28%	3.80%
FortisAlberta	37.0%	9.28%	3.43%
Ontario MEUs [1/]	40.0%	9.05%	3.62%
Newfoundland Power	44.5%	9.47%	4.21%
AVERAGE	40.6%	9.27%	3.77%
Pacific Northern Gas	**36.0%**	**9.40%**	**3.38%**
Comparables			
AltaGas Utilities	41.0%	9.28%	3.80%
ATCO Pipelines	43.0%	9.28%	3.99%
Gazifère	40.0%	9.68%	3.87%
Natural Resource Gas	50.0%	9.15%	4.58%
AVERAGE	43.5%	9.34%	4.06%

1/ Rate base $250 million to $1 billion

2. Changes in capital and economic conditions warrant a re-estimation of the fair return for a benchmark low risk utility; these changes are supportive of higher allowed returns in Canada than those currently prevailing.

3. The re-estimation of the fair return should give weight to each of the tests that have traditionally been used, that is, the equity risk premium test, the discounted cash flow test and the comparable earnings test. My estimation of the fair return on equity for a benchmark low risk utility using the three tests follows.

C. EQUITY RISK PREMIUM TEST

1. Conceptual Underpinnings

The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. The equity risk premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

The estimation of the required equity risk premium, for either the market as a whole or a specific utility, is not an exact science. Hence, it is necessary to evaluate a broad spectrum of data and apply alternative risk premium estimation approaches to arrive at a reasonable determination of the required equity risk premium.

There are two broad approaches to estimating the equity risk premium for a utility. The first begins with an estimate of the expected equity risk premium for the entire equity market (i.e., the equity market portfolio), subsequently adjusted to reflect the risk of a utility relative to the market as a whole. The second approach develops the risk premium directly for a particular stock or industry (e.g., utilities). In both approaches, the estimated equity risk premiums are obtained by subtracting the estimated risk-free rate from the estimated expected return on the market portfolio or the individual industry/stock. The expected equity risk premium can be developed: (1) from an analysis of historic market risk premiums and (2) from prospective market risk premiums based on discounted cash flow (DCF) estimates of the expected market return. DCF-based estimates of the cost of equity comprise the dividend yield plus investor expectations of longer-term growth.

The equity risk premium test, similar to the other tests used to arrive at a fair return, is forward-looking, that is, it is intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability.

Because the risk premium test is forward-looking:

1. Historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions; and,

2. Direct estimates of the forward-looking risk premium need to supplement measurement of the risk premium by reference to historic data.

2. <u>Risk-Free Rate</u>

The point of departure for applying the equity risk premium test is a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable. The risk-free rate, for purposes of this analysis, is the forecast 30-year Canada yields, as has been used by the BCUC in establishing the allowed return under the automatic adjustment mechanism.

The forecast 30-year yield is based on a consensus forecast of 10-year Canada bonds plus the spread between 10- and 30-year Canadas. *Consensus Forecasts*, Consensus Economics (May 2005), anticipates that the 10-year yield 3-months and 12-months hence will be 4.5% and 4.9% respectively, for an average of 4.7%. The average April 2005 spread between 10- and 30-year Canadas was 44 basis points, which, when added to the 10-year forecast, indicates a long-term (30-year) Canada bond yield of 5.14%, rounded for purposes of applying the risk premium tests to 5.25%.

3. <u>Risk-Adjusted Equity Market Risk Premium Test</u>

a. <u>Conceptual and Empirical Considerations</u>

The risk-adjusted equity market risk premium approach to estimating the required utility equity risk premium entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment required for the benchmark low risk Canadian utility; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the benchmark utility equity risk premium. The cost of equity is thus estimated as:

$$\begin{array}{c}\text{Risk-}\\\text{Free}\\\text{Rate}\end{array} + \left\{\begin{array}{c}\text{Relative}\\\text{Risk}\\\text{Adjustment}\end{array} \quad \text{x} \quad \begin{array}{c}\text{Market}\\\text{Risk}\\\text{Premium}\end{array}\right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure what an equity investor should require as a return within the context of a diversified portfolio. Its focus is on the minimum return that will allow a company to attract equity capital. In its simplest form, the CAPM posits the following relationship between the required return on the risk-free investment and the required return on an individual equity security (or portfolio of equity securities):

$$R_E = R_F + b_e (R_M - R_F)$$

where,

R_E = Required return on individual equity security
R_F = Risk-free rate
R_M = Required return on the equity market as a whole
b_e = Beta on individual equity security.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities; therefore, the shareholder requires no compensation to bear those risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events, which also change the required return on the market.

In practice, the beta is a calculation of the historical correlation between the overall equity market, as proxied in Canada by the S&P/TSX Composite, and individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, it has disadvantages, which call into question placing sole reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Appendix A.

The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between risk (beta) and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> "Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn." (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French in "The CAPM: Theory and Evidence" (Summer 2004), Journal of Economic Perspectives, Volume 18, Number 3, pp. 25-26:

> "The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The

> CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid."

Fama and French have developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM.[31]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> "Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp." (page 240)

[31] The additional factors are size and book to market.

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> "Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart."[32]

My analysis to test for the presence of a positive relationship between market return and beta in the Canadian equity market is set out in Appendix A. This analysis generally shows a negative relationship between the calculated, or "raw", beta and return, the opposite of the model's premise.

In brief, the observations and analysis caution against reliance on beta as the sole measure of risk and the predictor of equity returns. The estimate of the relative risk adjustment should consider relative total risk, not solely the systematic market risk that beta is intended to measure. Moreover, they highlight the importance of reliance on multiple equity risk premium tests, as well as the other traditional tests (DCF and comparable earnings) in estimating a fair return on equity.

b. <u>Equity Market Risk Premium</u>

i. Factors to Consider

My estimate of the expected/required equity market risk premium was made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but

[32] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

should also take into account the U.S. equity market to be a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The rationale is two-pronged. First, as discussed in Section IV, the historic Canadian equity and government bond returns incorporate various factors that make them questionable as a good representation of future returns (e.g., capital held captive in Canada, lack of market liquidity and diversity, higher risk of Government of Canada bond market historically, which has since dissipated). Second, the U.S. economy and capital market, which is increasingly integrated with the Canadian economy and capital market, has historically been the largest recipient of Canadian investment funds outside of Canada, and is considered a broadly diversified global benchmark market.

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Hence, focus should be placed on periods whose economic characteristics, on balance, are more closely aligned with what today's investors are likely to anticipate over the longer-term. The focus on the longer-term reflects the perpetual nature of equity.

Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;

2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;

3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;

4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

Consequently, I focused on post-World War II returns, that is, 1947-2004.

ii. Historic Risk Premiums

As previously discussed, in arriving at an estimation of the market risk premium, I looked to both Canadian and U.S. historic returns and risk premiums. The average post-World War II U.S. and Canadian historic risk premiums show the following:

Table 8

Historic Average Risk Premiums (1947-2004)		
	Arithmetic	**Geometric**
Canada	5.3%	4.5%
U.S.	7.0%	6.2%

Source: Schedule 8.

In light of the increase in Canadian investors' purchases of U.K. equities,[33] I also looked at the historic U.K. indicated market risk premiums over the same period. The U.K. historic premiums were in the range of 5.6% to 6.0% (geometric and arithmetic averages respectively) from 1947-2004 (see Schedule 8).

iii. Superiority of Arithmetic Averages

When historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages, not geometric (compound) averages, should be used. Expressed simply, the arithmetic average recognizes the uncertainty in the stock market; the geometric average removes the uncertainty by smoothing over annual differences.

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance,* Boston: Irwin McGraw Hill, 2000 (p. 157), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for this purpose is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

> "The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when

[33] In 1995, U.K. equities represented only 4.5% of all foreign equities purchased by Canadian investors. In 2004, they represented 53%. Purchases of U.S. and U.K. equities, in total, accounted for 88% of all foreign equities purchased by Canadian investors in 2004 (Statistics Canada).

> compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . .in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital."[34]

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

> "The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.015 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns."

In its 1999 decision, the Commission concluded that my risk premium "which relies exclusively on a one year holding period, is likely to be upwardly biased." In arriving at that conclusion, the Commission considered using the arithmetic average to estimate the expected risk premium to be synonymous with an investment holding period of one year. Reliance on the arithmetic average to estimate the future equity risk premium is not premised on a one year holding period. It is premised on the uncertainty with respect to each year's return during the holding period, whatever that may be. When the arithmetic average of historic annual returns is used to develop the expected value of the return, every

[34] An illustration from Ibbotson Associates demonstrating why the arithmetic average is more appropriate than the geometric average for estimating the expected risk premium is found in Appendix A.

achieved return considered becomes one possible future outcome for each year the security will be held. Each historic return is thus implicitly assigned an equal probability of occurring during each year of the holding period. The resulting expected value of the risk premium is the arithmetic average of all of the past premiums considered, whether the expected future holding period is one year or twenty years.

iv. Future vs. Historic Risk Premiums

The equity market "bubble and bust" has spawned a number of studies of the equity market risk premium that have speculated the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

However, the preponderance of the increase in price/earnings ratios in the U.S. market occurred during the 1990s. The P/E ratio[35] of the S&P 500 averaged 14 times from 1926-1989, with no discernible upward trend.[36] From 14.7 in 1989, the P/E ratio rose to a high of 32.3 in 1998, and averaged 23 from 1990-2000. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity

[35] Coincident price and earnings.
[36] The average from 1947-1989 was 13.3 times.

market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent investors to the sidelines.[37] Nevertheless, the P/E ratio for the S&P 500 remained at a somewhat elevated level relative to history.[38]

To assess the impact of rising P/E ratios, I analyzed the equity returns of the S&P 500 achieved prior to 1990, that is, the post-World War II period prior to the upward trend in P/E ratios. That analysis indicates that the achieved equity returns for the S&P 500 averaged 12.3% (geometric average) to 13.5% (arithmetic average) from 1947-1989. The corresponding returns from 1947-2004 were 11.9% (geometric average) to 13.2% (arithmetic average). Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1947-2004 period than over the 1947-1989 period. Consequently, based on history, an expected value for the U.S. equity market return of 12.0-13.0% is not unreasonable. At the 2006 forecast of the long-term (20-year) Treasury bond yield of 5.5%,[39] this equates to an expected value for the equity risk premium of approximately 7.0%. Relative to the consensus forecast yield over the longer-term of approximately 6.0%,[40] the risk premium would be 6.0-7.0%.

My review of Canadian equity returns over the same period indicates similar results. The returns for the Canadian equity market were 11.9% (geometric average) to 13.1% (arithmetic average), very similar to the U.S. returns. In

[37] Lowered expectations for the equity market have led investors to focus elsewhere for superior risk/reward opportunities, e.g., real estate, and private equity, suggesting that the expectations for the public equity market at present may be out-of-line with return requirements. As previously noted, investors' experiences during the equity market "bust" have been a key factor in explaining the recent burgeoning of the income trust market in Canada.
[38] At the end of May 2005, the S&P 500 forward P/E ratio was 16, based on current price/forecast 2005 earnings.
[39] For first three quarters of 2006, Blue Chip *Financial Forecasts*, June 1, 2005.
[40] From Consensus Economics, *Consensus Forecasts* (April 10, 2005); equals the forecast of 10-year Treasury notes of 5.6% for 2006-2015 plus a 10-year/long-term Treasury spread of 43 basis points.

relation to the near-term (5.25%) and longer-term forecasts (5.75%)[41] of the 30-year Canada bond yield, an expected value of the equity market returns in the range of 12.0-13.0% indicates an expected value for the equity risk premium of approximately 6.5%.

While the above analysis demonstrates no trend in market equity returns, the measured risk premiums have declined. The arithmetic average achieved risk premium in Canada from 1947-1989 was 7.6%; in the U.S. it was 8.5%. By comparison, the corresponding Canadian and U.S. 1947-2004 risk premiums were 5.3% and 7.0% respectively. An analysis of the underlying causes shows that high bond returns over the period 1980-2004 are the primary factor in the experienced decline in risk premiums, not a downward trend in stock returns. (See Appendix A for a full discussion).

With interest rates currently at historically low levels, and more likely to increase rather than decrease further, the recent average bond returns (12% over the past 25 years) overstate a reasonable forward-looking expectation of bond returns, as embedded in current yields. The current low level of long-Canada yields limits the possibility of future capital gains. Thus, a reasonable expected value of the long Canada bond return is the forecast long Canada yields, rather than the historic average.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.5%, based on both the Canadian and U.S. equity market returns. (See Appendix A). Based on the near-term forecast for long Canadas of 5.25%, and an expected equity market return of 11.5-12.5%, the indicated Canadian equity market risk premium would be in the range of 6.25-7.25%, or approximately 6.75%.

[41] Long-term (2006-2015) forecast for 10-year Canada bond yields of 5.4% plus historic spread between 10- and 30-year Canadas of approximately 35 basis points, from Consensus Economics, *Consensus Forecasts*, April 2005.

v. Estimate of Equity Market Risk Premium

Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast level of long-term government bond yields is 6.0-6.5%. The 6.0-6.5% estimate of the equity market risk premium explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

c. Relative Risk Adjustment

The relative risk adjustment that is applicable to a benchmark low risk utility is approximately 0.65, based on total risk as measured by standard deviations of market returns and adjusted betas. The analysis that follows explains how the relative risk adjustment was derived.

i. Total Market Risk

My analysis of the relative risk adjustment starts with a recognition that investors are not perfectly diversified and that they expect some compensation for assuming company-specific risk. It also recognizes that, while investors can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot. Thus, a risk measurement which reflects those considerations is relevant. These considerations point to a focus on total market risk, rather than solely the non-diversifiable risk which beta attempts to measure. The infirmities of beta as a measure of risk, as well as the absence of an observable relationship between "raw" betas and the market return on equity provide further support for reliance on other measures of risk.

The standard deviation of market returns is the principal measurement of total market risk. To compare the relative total risk of Canadian utilities, the monthly standard deviations of total market returns for the S&P/TSX Index and for each of the 10 major Sectors of the S&P/TSX Index were calculated, over recent five-year periods. The standard deviations for the Utilities Index show that the absolute volatility of utility stocks has risen significantly since the middle of the 1990s. The standard deviation of returns for the Utilities Index for the five-year period ending 2004 was approximately 30% higher than the corresponding value for the five-year period ending 1997 (Schedule 15).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the standard deviations of the S&P/TSX Index and the simple mean of the standard deviations of the 10 Sectors. Table 9 below shows the ratios of the standard deviations of the Utilities Index to those of the S&P/TSX Index and the 10 S&P/TSX Sectors. Focusing on the relationship between the standard deviation of the Utilities Index and the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment of approximately 0.60-0.70.

Table 9

Five-Year Period Ending	Standard Deviation of S&P/TSX Utilities Index as a Percent of:		
	Standard Deviation of S&P/TSX	Standard Deviation of 10 S&P/TSX Sectors	
		Mean	Median
1997	88%	64%	74%
1998	81%	65%	65%
1999	83%	63%	61%
2000	89%	69%	71%
2001	86%	67%	73%
2002	84%	62%	68%
2003	90%	63%	70%
2004	89%	61%	72%

Source: Schedule 15.

ii. Historic "Raw" Betas

Since beta remains the risk measure that underpins the application of the simple CAPM (of which the risk-adjusted equity market risk premium test is a variant), I also considered betas in arriving at the estimated relative risk adjustment for a benchmark utility. The following table summarizes "raw" betas[42] for individual major publicly-traded Canadian regulated electric and gas companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector over five-year periods ending 1993 through 2004.[43] The betas were divided into two periods: betas ending in the years 1993-1998 and betas ending in the years 1999-2004. The

[42] The "raw" beta refers to the simple regression between 60 monthly percentage changes in the price of a utility or utility index and the corresponding percentage change in the price of the equity market index (the S&P/TSX Composite).

[43] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

betas were divided into two separate periods to highlight the impact of the "tech bubble" on the measured betas.

Table 10

Canadian Utility "Raw" Betas (Average of 60 month betas ending in each of indicated years)			
Ending in Years:	**Individual Canadian Utilities (Median)**	**TSE 300 Gas/Electric Utility Index**	**S&P/TSX Utilities Sector**
1993-1998	0.47	0.49	0.60
1999-2004	0.14	0.23	0.00

1/ Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., Terasen Inc., and TransCanada Corp.

Source: Schedule 11.

The observed recent decline in the measured utility betas in 1999-2004 can be traced to three factors: (1) the technology sector bubble in general; (2) the dominance in the TSE 300 of two firms during this period, Nortel Networks and BCE; [44] and (3) the negative impact of rising interest rates on utility stocks while the equity market composite was soaring. Chart 1 in the Statistical Exhibit graphically demonstrates the decoupling between utility stocks and the S&P/TSX Composite between 1999 and mid-2002 period, when the equity market "boom and bust" was most prevalent. As a result, the disparate movements in utility equities relative to the TSE 300 during this period produced lower measured utility betas.

The decoupling between utility shares and the rest of the market during the technology bubble (and subsequent melt-down of Nortel and other high tech

[44] The impact on the S&P/TSX Utilities Index "raw" beta due solely to the dominance of Nortel Networks in the TSE 300 can be estimated by excluding Nortel from the TSE 300 and recalculating the beta. The recalculated "raw" 1997-2001 beta, for example, was 0.18, versus -0.03 inclusive of Nortel; see Schedules 11 and 12.

stocks) should not be interpreted as a change in the relative riskiness of utility shares, but rather as a further indication of the weakness of beta as the sole measure of the relative equity return requirement.[45]

However, a further review of Chart 1 shows that, beginning in mid-2002, the equity market composite and the utility equities began to once again exhibit a correlation that, graphically, resembles more closely the typical relationship observed prior to the market "boom and bust". Indeed, when betas are calculated over recent periods that largely eliminate the "boom and bust" period, utility betas are higher. The calculations of the "raw" betas (including and excluding Nortel, the latter to eliminate any lingering impact of Nortel) over the 36-month period 1/2002-12/2004 and the 30-month period 7/2002-12/2004 shows the following:

Table 11

Canadian Utility Raw Betas				
	Period			
	1/2002-12/2004		**7/2002-12/2004**	
	Including Nortel	Excluding Nortel	Including Nortel	Excluding Nortel
Individual Canadian Utilities:				
Mean	0.28	0.36	0.35	0.42
Median	0.31	0.38	0.39	0.42
S&P/TSX Utilities Sector	0.34	0.46	0.44	0.55

Source: Schedule 14.

Table 11 indicates that the betas of the utilities have been gradually rising as the Nortel impact has been disappearing from the equity market composite index.

[45] Schedule 13 shows that utilities were not the only companies whose betas were negatively impacted by the speculative bubble and subsequent market decline. To illustrate, the 60 month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87.

iii. Impact of Interest Sensitivity on Relative Risk

Utilities are interest-sensitive stocks and thus tend to move with interest rates, which frequently move counter to the equity market. Consequently, utility equity price movements are correlated not only with the stock market, but also with movements in the bond market. Thus, the interest-sensitivity of utility shares is not fully captured in the calculated "raw" betas, which simply measure the covariability between a stock and the equity market composite.[46]

A regression of the monthly returns on the TSE Gas/Electric Index against the TSE 300 over the period 1970-August 1999[47] shows the following:

$$\begin{array}{lcl} \text{Monthly TSE Gas/Electric Return} & = & 0.0054 + 0.58 \left\{ \begin{array}{c}\text{Monthly} \\ \text{TSE 300} \\ \text{Return}\end{array} \right\} \\ \text{t-statistic} & = & \qquad\qquad 16.5 \\ R^2 & = & 43.3\% \end{array}$$

The relationship quantified in the above equation suggests a relative risk adjustment of close to 0.60. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 43%. That means 57% of the volatility remains unexplained.

When the analysis is expanded to include Government of Canada bond returns, the following regression is produced:

$$\begin{array}{lcl} \text{Monthly TSE Gas/Electric Return} & = & 0.0018 + 0.48 \left\{ \begin{array}{c}\text{Monthly} \\ \text{TSE 300} \\ \text{Return}\end{array} \right\} + .52 \left\{ \begin{array}{c}\text{Monthly Long} \\ \text{Canada Bond} \\ \text{Return}\end{array} \right\} \\ \text{t-statistics} & = & \qquad\qquad 14.5 \qquad\qquad\qquad 9.5 \\ R^2 & = & 55.0\% \end{array}$$

[46] In theory, the beta should be measured against the entire "capital market" including short-term debt securities, bonds, real estate, etc. In practice, it is measured using the equity market only.
[47] Excludes the anomalous market "boom and bust"/"Nortel effect" period.

When interest rates (as proxied by government bond returns) are added as a further explanator of the observed volatility in utility stock prices, significantly more of the volatility is explained (55% versus 43%).

The second regression equation suggests that utility shares have had approximately 50% of the volatility of the equity market as well as approximately 50% of the volatility of the bond market, consistent with utility common stocks' interest sensitivity. Using an expected equity market return of 12.0%, and a long Canada bond return (equal to the forecast yield) of 5.25%, the equation indicates an expected utility return of 10.8%. When the 10.8% utility return is expressed as an equity risk premium relative to the 5.25% long Canada yield, the indicated relative risk adjustment is close to 80-85%.[48]

iv. Use of Adjusted Betas

The deficiencies in "raw" betas can be mitigated by using adjusted betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0.[49] Use of adjusted betas implicitly recognizes that "raw" utility betas are not adequate explanators of utility returns; for example, they do not capture utilities' interest rate sensitivity. The objective of the relative risk adjustment is to predict the investors' required return. Adjusted betas provide a better correlation between utility risk and return than "raw" betas.

[48] $\frac{10.8\% - 5.25\%}{12.0\% - 5.25\%} = .82.$

[49] *Value Line*, Bloomberg and Merrill Lynch all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

Table 12 below summarizes the average of the adjusted five-year betas ending in 1993 to 1999 (pre-"Nortel effect") and those calculated over the longest recent period excluding the Nortel effect (30-month period 7/2002-12/2004).[50]

Table 12

Canadian Utility Adjusted Betas

Periods	**Individual Canadian Utilities (Median)**	**TSE 300 Gas/Electric Utility Index**	**S&P/TSX Utilities Index**
Five-Year Betas ended 1993 to 1998 (Average)	0.64	0.66	0.73
30-Month Betas (7/2002 to 12/2004)	0.61	N/A	0.70

Source: Schedules 11 and 14.

The adjusted betas indicate a relative risk adjustment of approximately 0.60-0.70.

v. Relative Risk Adjustment

Based on the preceding analysis of standard deviations of market returns and betas, in my opinion, the relative risk adjustment for a benchmark low risk utility is approximately 0.65.

d. <u>Benchmark Utility Equity Risk Premium</u>

I estimated the equity market risk premium at a long Canada yield of 5.25%, at approximately 6.0-6.5%. At an equity market risk premium of 6.0-6.5% and a relative risk adjustment of 0.65, the indicated benchmark utility equity risk premium is 4.0%.

[50] Adjusted utility beta = 2/3 ("raw" beta) + 1/3 (market beta of 1.0); the 7/2002-12/2004 "raw" betas were calculated excluding Nortel from the S&P/TSX Composite Index (see Schedule 14).

4. Utility-Specific Equity Risk Premium Analysis

The risk-adjusted equity market risk premium test (discussed above) estimates the required utility equity risk premium indirectly. That is, it estimates an equity risk premium for the equity market as a whole, then adjusts it for the relative risk of a benchmark utility. The following analyses estimate the equity risk premium for a benchmark utility directly, by analyzing utility equity return data. The analyses below focus on both long-term historic utility equity risk premiums and an equity risk-premium test derived from forward-looking monthly estimates of the required utility equity return.

The following two sections provide the results of that analysis.

a. Historic Utility Equity Risk Premiums

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

Over the longer-term (1956-2004),[51] achieved utility equity risk premiums were 3.8-4.4% for Canadian gas and electric utilities, based on both geometric and arithmetic average returns.[52] For U.S. gas utilities, the corresponding historic equity risk premiums averaged approximately 5.4-6.0% over the entire post-World War II period (1947-2004). The corresponding risk premiums for U.S. electric utilities were 4.3-5.0% (Schedule 16). The historic equity risk premiums for both Canadian and U.S. utilities support an expected equity risk premium

[51] The longest period for which Canadian utility data are available from the TSE.
[52] Based on the Gas/Electric Index of the TSE 300 (through 1987) and on the S&P/TSX Utilities Index from 1988-2004.

estimate for a benchmark Canadian utility in the range of 4.25-5.0%, or approximately 4.75%.

b. DCF-Based Equity Risk Premium Test

i. Derivation of Model

A forward-looking equity risk premium test was also performed, using the discounted cash flow model (DCF) to estimate expected utility returns over time. The discounted cash flow model, discussed in more detail in Section IV.D, estimates the utility required return on equity at a point in time. The required return on equity is estimated as the dividend yield on the stock plus the expected growth in dividends over the longer-term. The very nature of the discounted cash flow estimate of the required return lends itself to an analysis of the relationship between utility equity risk premiums and interest rates. Each DCF "point in time" estimate of the required return can be matched with a corresponding "point in time" interest rate. The difference between the two is thus an indicator of the required utility equity risk premium at a given level of interest rates.

Monthly cost of equity estimates were constructed using the DCF model for a sample for the period 1993-2004.[53] The DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[54] plus the expected dividend yield. The equity risk premium is equal to the difference between the average DCF cost of equity for the sample and the corresponding 30-year Treasury yield for the period.[55]

[53] Subsequent to Open Access implemented via FERC Order 636.
[54] The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.
[55] A full explanation of the sample selection and the construction of the model is found in Appendix B.

ii. Choice of Utility Sample

In conducting this test, I relied on U.S. local gas distribution utilities (LDCs) as a proxy for a benchmark low risk utility. The reasons for choosing U.S. LDCs are as follows:

First, there are an insufficient number of forward-looking estimates of long-term growth rates for Canadian utilities that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums from Canadian data. A consensus estimate of investors' growth expectations is key to the application of the discounted cash flow model.

Second, U.S. and Canadian utilities are reasonable proxies for one another, particularly in today's global capital market. Although there may be company-specific differences in business and financial risk, the impact of those differences is minimized by selecting only relatively pure-play LDCs with similar debt ratings to the typical Canadian utility.

Third, relatively pure-play LDCs were selected for this specific purpose because they have not experienced the same degree of restructuring as other regulated industries in the U.S., e.g., electric utilities. Reliance on relatively pure-play gas distribution utilities mitigates the impact on the required returns of changes in the business risk environment, and thus allows the relationship between the utility equity risk premium and interest rates to be isolated.

Fourth, the selected U.S. LDCs are of relatively low business risk, on average, of a similar level to that of an average risk investor-owned Canadian utility.

iii. Investor Growth Expectations

In the application of the DCF-based equity risk premium test, the Commission, in its 1999 decision, raised the issue of the reliability of the earnings growth forecasts as a measure of investor expectations. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. For the sample of LDCs used in the DCF-based risk premium test, the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1993-2004 period of analysis was 5.2%. That growth rate is quite similar to the long-term expected nominal growth in the economy as a whole over the same period.[56] An expected growth rate close to that of the economy as a whole is not out-of-line with the level of growth investors in a relatively mature industry like gas distribution could reasonably expect over the longer-term.

A second means of assessing the reasonableness of the forecast growth rates is to compare the resulting DCF costs to the returns that have been allowed for U.S. LDCs over the same period. Since the DCF test has traditionally been the principal model relied on by U.S. regulators, the allowed returns for U.S. gas LDCs should track their DCF costs of equity. Moreover, since different analysts and regulators rely on different DCF models and measures of growth expectations, the allowed returns will reflect the results of the various DCF models and measures of growth (e.g., constant growth versus multi-stage models; forecast versus historic growth rates). Consequently, the allowed returns should not, in the aggregate, represent either an upwardly or downwardly biased measure of the utility cost of equity.

[56] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1993-2004), has been 5.3% over the same period covered by the DCF-based risk premium test.

The average DCF cost in my DCF-based risk premium model from 1993-2004 was 10.2%; the average allowed return for U.S. gas LDCs from 1993-2004 was approximately 11.1%[57] The actual allowed returns for LDCs were, on average, some 90 basis points higher than the indicated DCF costs of equity in my equity risk premium study. On this basis, there is no reason to conclude that the DCF estimates in the DCF-based equity risk premium test are upwardly biased.

iv. DCF-Based Utility Equity Risk Premium

For the sample of U.S. LDCs, the DCF-based risk premium test indicates an average risk premium over the 1993-2004 period of 4.2% (Schedule 17); the corresponding average long-term government bond yield was 6.0%, close to the longer-term forecasts for both Canada and the U.S, but higher than the near-term forecast yield of 5.25%.

The data suggest that there has been a relationship between the risk-free rate (as proxied by the long-term government bond yield) and utility equity risk premiums. To test the relationship between interest rates and risk premiums, a simple regression analysis between the monthly 30-year Treasury yields and the corresponding equity risk premiums was conducted. The indicated relationship was:

$$\text{Equity Risk Premium} = 8.20 - 0.66\left\{\begin{array}{c}\text{30-Year}\\ \text{Treasury}\\ \text{yield}\end{array}\right\}$$

$$\text{t-statistic} = -11.4$$

$$R^2 = 48\%$$

[57] Regulatory Research Associates, *Regulatory Focus: Major Rate Case Decisions, January 1990-December 2004*.

At the forecast 30-year government bond yield of 5.25%, the indicated utility equity risk premium is 4.7%.

I also tested the relationship between the spreads between long-term utility and government bond yields in conjunction with the change in the yield on long-term government bond yields. As indicated in Section IV.B.5.b, the magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' perception of risk.[58]

To estimate the relationship, I performed a regression analysis over the 1993-2004 period using the utility risk premium[59] as the dependent variable, with the corresponding long-term government bond yield and spread between long-term high grade utility[60] and government bond yields as the two independent variables.

The analysis indicated the following:

LDC Risk Premium = 5.3 - .37 TY + .81 Spread

where,

TY = 30-year Treasury Yield

Spread = Spread between High Grade Utility Bond Yields and 30-year Treasury Yields

Thus, the data indicate that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.[61]

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[58] Or, alternatively, willingness to take risks.
[59] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[60] Based on Moody's long-term A rated utility bond index.
[61] Statistics for the equation:

R^2	68.0%
t-statistics:	
Long-term bond yield:	-6.8
Utility/government bond yield spread:	9.5

The spread between 30-year Canadian A-rated utility bonds and 30-year Canadas was approximately 120 basis points at the end of May 2005. Using a forecast long Canada yield of 5.25% and an A-rated utility bond/long Canada spread of 120 basis points, the indicated utility risk premium is 4.3%.

Based on both the single and two independent variable approaches, the DCF-based risk premium test results indicate a utility equity risk premium in the range of 4.3-4.7%, or a mid-point of 4.5%, at a long-term government bond yield of 5.25%.

5. Equity Risk Premium Test "Bare-Bones" Cost of Equity

The estimated equity risk premiums based on the three methodologies are as follows:

Risk Premium Test	Risk Premium
Risk-Adjusted Equity Market	4.0%
Historic Utility	4.75%
DCF-Based	4.5%

On balance, the three approaches indicate an equity risk premium applicable to a benchmark Canadian utility of 4.0-4.75%. At a forecast long Canada yield of 5.25%, the "bare-bones" cost of equity is 9.25-10.0%. An allowance for financing flexibility needs to be added to this result.

6. Financing Flexibility Allowance

An adjustment to the equity risk premium test result for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when industrials of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive industrials of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such industrials, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of industrials to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> "This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values."[62]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility

[62] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[63]

The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators. In both G-80-99 and G-35-94, the BCUC explicitly included a 50 basis point flotation cost adjustment when it set the benchmark return on equity.

7. Equity Risk Premium Test Results

The indicated return on equity for a benchmark average risk utility using the equity risk premium approach is in the range of 9.75-10.5%. The following table summarizes the components of the test.

Table 13

Risk-Free Rate	5.25%
Equity Risk Premium	4.0-4.75%
"Bare-Bones" Cost of Equity	9.25-10.0%
Financing Flexibility Allowance	0.50%
Return on Equity	9.75-10.5%

[63] The financing flexibility allowance is estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x “bare-bones” cost of equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a dividend payout ratio of 65% and a cost of equity of 10.0%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \text{ x } 10\%}{1 + [.35\ (1.075 - 1.0)]}$$

$$\text{ROE} = 10.5\%$$

The difference between the ROE and the "bare-bones" cost of equity of 50 basis points is the financing flexibility allowance.

D. DISCOUNTED CASH FLOW TEST

1. <u>Conceptual Underpinnings</u>

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows.

Although it has flaws, the DCF model has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM (or more generally the equity risk premium test as applied by Canadian regulators) indirectly estimates the cost of equity. In light of the recent volatility in the equity markets, and rapid shifts in investors' risk perceptions, it is important to rely on multiple approaches to estimating the cost of capital. The DCF model provides a widely used alternative to CAPM.

The principal issues in the application of the discounted cash flow test are:

a. The determination of the appropriate form or forms of the model to be applied.
b. The selection of a sample of utilities of reasonably comparable risk to the benchmark low risk utility to which the model or models will be applied.
c. The determination of the appropriate measure of investor growth expectations to be utilized.

2. DCF Models

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. In determining the DCF cost of equity for a benchmark utility, I utilized both a constant growth and a two-stage model.[64]

3. Proxy Utilities

The discounted cash flow test was applied to a sample of relatively low risk U.S. gas and electric utilities that are intended to serve as a proxy for the Canadian benchmark utility.[65]

4. Investors' Growth Expectations

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short

[64] The two-stage model is a form of multiple period model. A complete description of the construction of the models is found in Appendix C.

[65] The reasons for reliance on U.S. utilities are identical to those set forth in Section IV.C.4.b. However, a broader sample of utilities was employed for purposes of applying the DCF test than for the DCF-based equity risk premium test. The DCF-based equity risk premium test estimates the relationship between the utility equity risk premium and interest rates over time. Consequently, it is necessary to focus on utilities that remained relatively "pure-play" over the test period. The DCF test conducted in this section estimates the current cost of equity; the suitability of a utility as a proxy for the benchmark low risk utility depends only on its current risk profile. Selection criteria are provided in Appendix C.

of those returns. To mitigate that circularity, it is important to rely on proxies, rather than the subject company.

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. Thus, in applying the DCF test, I relied solely on published forecast growth rates that are readily available to investors. The reasons for sole reliance on forecast growth rates are as follows:

First, various studies have concluded that analysts' forecasts are a better predictor of growth than naïve forecasts equivalent to historic growth. Moreover, analysts' forecasts have been shown to be more closely related to investors' expectations than historic growth rates.[66]

[66] Empirical studies that conclude that investment analysts' growth forecasts serve as a better surrogate for investors expectations than historic growth rates include: Lawrence D. Brown and Michael S. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings", *The Journal of Finance*, Vol. XXXIII, No. 1, March 1978; Dov Fried and Dan Givoly, "Financial Analysts Forecasts of Earnings, A Better Surrogate for Market Expectations", *Journal of Accounting and Economics,* Vol. 4 (1982); R. Charles Moyer, Robert E. Chatfield, Gary D. Kelley, "The Accuracy of Long-Term Earnings Forecasts in the Electric Utility Industry", *International Journal of Forecasting* Vol. I (1985); Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management*, Spring 1986, and, James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History", *The Journal of Portfolio Management*, Spring 1988; David Gordon, Myron Gordon and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

The Vander Weide and Carleton study cited

> "found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price [and that these results] also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."

The Gordon, Gordon and Gould study concluded,

> "…the superior performance by KFRG [forecasts of [earnings] growth by securities analysts] should come as no surprise. All four estimates [securities analysts' forecasts plus past growth in earnings and dividends and historic retention growth rates] rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

Second, to the extent history is relevant in deriving the outlook for earnings, it should already be reflected in the forecasts. Therefore, reliance on historic growth rates is at best redundant, and, at worst, potentially double counting growth rates which are irrelevant to future expectations.

Third, to the extent that restructuring in the utility industries altered investors' growth expectations relative to history, historical growth rates are highly suspect as a measure of investor expectations.

Fourth, reliance on historic growth rates to measure investor expectations to some extent renders the replication of that growth a self-fulfilling prophecy. Reliance on forecast growth rates avoids the circularity inherent in historic growth rates.

In Section IV.C.4.b.*iii*, in my application of the DCF-based equity risk premium test, I addressed the Commission's concern in Decision G-80-99 that growth forecasts are vulnerable to analyst optimism. The same discussion applies here. In addition, in my application of the discounted cash flow test, I have addressed the Commission's concern directly by incorporating *Value Line* forecasts of earnings growth in addition to the I/B/E/S[67] consensus forecasts. As an independent research firm, *Value Line*, has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors, as analysts associated with investment banking firms might have. Therefore, incorporating *Value Line* estimates of earnings growth is a means of assessing the reasonableness of the results obtains through use of the I/B/E/S consensus estimates.

The median *Value Line* expected long-term earnings growth rate for the utility sample was 4.5%; the corresponding I/B/E/S forecast was also 4.5% (see Schedules 20 and 21). This comparison suggests no upward bias in the I/B/E/S forecasts.

[67] As noted earlier, I/B/E/S is a leading provider of earnings expectations data.

5. DCF "Bare Bones" Cost of Equity

The results of the constant growth and two-stage DCF models indicate a required "bare-bones" return on equity of approximately 9.25%, as delineated in detail in Appendix C, and shown on Schedules 20-22.

6. The DCF Test and the Fair Return on Equity

The 9.25% DCF cost represents the return investors expect to earn on the current market value of their utility common equity investments. It is not, however, the return that investors expect the utilities to earn on the book value of their common equity. *Value Line*, which publishes its projections of utility ROEs quarterly, anticipates that the return on average common equity for the sample of utilities over the period 2008-2010 will be approximately 11.8% (Schedule 19).

There is a "disconnect" in logic if investors expect the allowed return on equity to be equal to the DCF cost of equity. When the market value deviates materially from the original cost book value to which the allowed return is applied. This has clearly been the case during the last business cycle. The average market/book ratio of the U.S. utility sample from 1993-2004 was approximately 170-175% (Schedule 19).

To illustrate the problem, assume that a utility has a market/book ratio of 175%. If the investor now expects the utility to earn a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value. The investor then experiences a capital loss of over 40%. The idea that an investor is willing to pay a price equal to 175% of book value in order to see the market value of his investment drop by over 40% is illogical.

There is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition. Under competition, equity market values tend to gravitate toward the replacement cost of the underlying assets. Absent inflation, the market value of firms operating in a competitive environment would tend to equal their book value or cost. This is due to the proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, when the market value equals the replacement cost of the productive capacity of the assets. However, the fact that inflation has occurred changes the above analysis. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past two business cycles, one would expect the market value of utilities to deviate systematically from the book value.

In principle, for a market-derived cost of equity (e.g., derived via the DCF or equity risk premium test) to produce a return compatible with the premise that regulation is a surrogate for competition, the cost of equity should be adjusted to reflect the replacement cost/book value ratio. Economic theory indicates that the replacement cost/book value ratio should correspond to the long-run equilibrium market/book ratio.[68] The replacement cost/book value ratio is, in turn, an estimate of the expected long-run equilibrium market value/book ratio that should be anticipated under competition.

[68] By repricing the equity of the utilities for past inflation, an approximation of the replacement cost can be made. To reprice the equity, each annual increment to common equity must be increased to reflect inflation experienced from the time the equity was added to the present. The total repriced equity is a proxy for replacement cost. The total repriced equity is then compared to the original cost book value of the equity to arrive at an estimate of the replacement cost/book value ratio. The resulting replacement cost/book value for the sample of utilities was 1.6, well in excess of 1.0 (See Schedule 19). Adjusting the DCF cost of equity of 9.25% to a return compatible with a long-run market/book ratio of 1.6, using the *Value Line* forecast earnings retention rate of approximately 35% (see Schedule 19), the indicated return on book equity would be close to 12.25%.

To mitigate the problem created by the divergence between market and book values, at a minimum, the DCF test result should be augmented by the same allowance for financial flexibility as applicable to the equity risk premium test results, i.e., a minimum allowance of 50 basis points. An adjustment to the DCF cost of equity of 9.25% for financing flexibility results in a return on book equity of 9.75%. Thus, the DCF test indicates a return on equity for a benchmark low risk Canadian utility of approximately 9.75%.

E. COMPARABLE EARNINGS TEST

1. Conceptual Underpinnings

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy.

The comparable earnings test is an implementation of the comparable earnings standard, as distinguished from the cost of attracting capital standard. The comparable earnings standard recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the cost of attracting capital standard relies on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable earnings standard, as well as the principle of fairness, suggest that, if competitive industrial firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable earnings standard when setting a just and reasonable return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. To illustrate, if the market value of an investment is $15 and the required return is 10%, the return, <u>in dollars</u>, expected by investors is $1.50. However, regulatory convention applies the market-derived return to the book value of the investment. If the book value of the investment is $10.00, application of a 10% return to the book value will result in a return, <u>in dollars</u>, of only $1.00. The cost of attracting capital tests, i.e., equity risk premium and discounted cash flow, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value. The comparable earnings test, however, does. It applies "apples to apples", i.e., a book value-measured return is applied to a book value-measured equity investment.

Depending on the economic/capital market environment, the reliability of the various tests used to estimate the fair return will vary. In the early 1990s, there was a dramatic shift in the inflationary environment. In combination with the restructuring of Canadian industry, and a prolonged recession, the reliability of the comparable earnings test was reduced. At that time, the fundamental changes in the economy rendered past earnings as an estimate of future earnings problematic.

Fourteen years have now transpired since the low inflation targets were adopted by the government; at no time during that period has the annual inflation rate exceeded three percent. In addition, there have been ten years of experience (1994-2004) since the industrial restructuring in Canada. A full business cycle has transpired, a cycle characterized, on average, by moderate growth and low to moderate inflation. The economic fundamentals of that cycle are similar to those expected for the next cycle. Under current economic circumstances, the usefulness of the comparable earnings test has been restored.

In its 1999 decision, the Commission expressed concern with (1) the use of accounting data in the comparable earnings test and (2) with sample selection. These two concerns are addressed below

a. Use of Accounting Data

The comparable earnings method is used to estimate the prospective rate of return expressed in relation to book values rather than the prospective rate of return expressed in relation to market values. It is, by necessity, calculated using accounting data. The comparable earnings method, using the reported earnings on book value, provides a means by which the broad trends in corporate profits can be pushed down to the level of comparable risk companies.

Much of the concern surrounding the use of accounting data at the time of Order G-80-99 can be traced to problems associated with the wide-scale restructuring of the Canadian economy in the early part of the last decade. As noted in Section IV.A, a full cycle of earnings subsequent to restructuring is now available, which permits a reliable application of the comparable earnings method. However, recognizing that non-recurring items for individual companies could impact the sample average, the focus is on the sample median values, which mitigates the effect of any potential outliers.

b. Sample Selection

The Commission's concern that the results of the comparable earnings test are sensitive to the sample selection is addressed through the designation of the selection criteria. The selection of a sample of companies from industrial sectors that is comparable to a benchmark utility must be made through the application of clearly defined, objective criteria designed to produce a low risk sample. By limiting the criteria to market factors (i.e., no accounting measures of risk), the potential for selection bias is eliminated. The selection criteria are set out in Appendix D.

2. Application of Comparable Earnings Test to Canadian Industrials

The principal issues in the application of the comparable earnings test are:

a. The selection of a sample of industrials of reasonably comparable risk to a benchmark low risk utility.

b. The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.

c. The need for any adjustment to the "raw" comparable earnings results if the selected industrials are not of precisely equivalent risk to the low risk benchmark utility.

The application of the comparable earnings test first requires the selection of a sample of industrials of reasonably comparable risk to a benchmark Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of the Canadian industrial companies (from consumer-oriented industries), resulting in a sample of 17 companies.[69]

Next, since industrials' returns on equity tend to be cyclical, the selection of an appropriate period for measuring industrial returns must be determined. The period selected should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., similar in terms of inflation and real economic growth. The period 1993-2004 provides a reasonable proxy for a future business cycle. The experienced returns on equity of the sample of 17 industrials over this period were in the approximate range of 13.0-13.5% (see Appendix D and Schedule 24).

The final step is to assess whether or not there is a need to adjust the "raw" comparable earnings results to reflect the differential risk of LDCs relative to the selected industrials. The comparative risk data indicate, on balance, the Canadian industrials and utilities are in a similar investment risk class. However, the industrials' one-notch lower debt ratings indicate that the industrials are of slightly higher investment risk than a benchmark utility (see Appendix D and Schedule 23). To recognize the industrials' marginally higher risk, the

[69] See Appendix D.

comparable earnings test, applied to a benchmark Canadian utility, should be interpreted as indicating a return of no less than 13.0%.

3. <u>**Application of Comparable Earnings Test to U.S. Low Risk Industrials**</u>

Due to the relatively small size of the Canadian sample – in large part a function of the size and make-up of the Canadian equity market – I also selected a sample of low risk U.S. industrials to serve as a check on the reasonableness of the Canadian results. The selection criteria were similar to those used for the Canadian industrial sample (see Appendix D). The greater breadth of the U.S. market allowed the selection of a sample of close to 200 companies in the same stable industries used to select the Canadian industrials. The experienced returns of the U.S. industrials were in the range of 14.0-14.75% (see Appendix D and Schedule 26). The comparative risk data indicate that the U.S. industrials are of similar risk to the Canadian industrials (see Schedule 25), and thus of slightly higher risk than a benchmark low risk Canadian utility. The returns of the U.S. sample of industrials underscore the reasonableness of the comparable earnings results as applied to the sample of Canadian industrials.

F. SUMMARY OF CONCLUSIONS ON FAIR RETURN ON EQUITY

The results of the three tests used to estimate a reasonable return on equity for a benchmark Canadian utility are summarized below:

Table 14

Test	"Bare-Bones" Cost of Equity	Fair Return on Equity
Equity Risk Premium	9.25-10.0%	9.75-10.5%
Discounted Cash Flow	9.25%	9.75%
Comparable Earnings	N/A	No less than 13.0%

In arriving at a reasonable return for a benchmark utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. The "bare-bones" cost of attracting capital based on these two tests is approximately 9.5%. Including the allowance for financing flexibility, the indicated return on equity is 10.0%. However, the comparable earnings test is also entitled to significant weight when setting a fair return that balances both ratepayer and shareholder interests. Based on all three test results, a fair return for a benchmark utility is 10.5%.

V. AUTOMATIC ADJUSTMENT MECHANISM FOR RETURN ON EQUITY

The Commission has had a mechanism in place to annually adjust allowed returns on equity since 1994. I support the continuation of such a mechanism. An automatic adjustment mechanism for setting returns on equity reduces the regulatory burden which annual return on equity analyses impose. Further, it results in increased predictability of the allowed returns and avoids any potential arbitrariness of the outcome.

There are, however, some disadvantages. The key disadvantage is that the flipside of greater predictability is the constraint placed on the regulator's flexibility in setting the allowed return, which may have adverse consequences for a utility in areas such as financing flexibility. Nevertheless, if there are adequate safeguards which permit the formula to be revisited or the utility to seek relief in circumstances of financial duress, I concur, in principle, with the implementation of a formula.

I condition my concurrence with "in principle" since the validity of any automatic adjustment formula depends on two key factors: (1) the reasonableness of the point of departure, that is, the benchmark return on equity, and (2) the reasonableness of the formula itself.

The current formula utilized by the Commission changes the allowed return by 100% of the change in forecast long Canada yields when long Canada bond yields are below 6.0% and changes the allowed return by 80% of the change in forecast long Canada bond yields when long Canada bond yields are between 6.0% and 8.0%. In my opinion, the different sliding scales for interest rates above and below 6.0% are not warranted and unfairly penalize the British Columbia utilities. There is no quantitative basis for the asymmetry of the formula, and its results put the British Columbia utilities at a distinct disadvantage relative to their peers. In its 1999 decision, the Commission implemented the 80% sliding scale at interest rates above 6% because "failing to have a sliding scale within that range could produce inadequate returns for the Utilities and result in capital attraction difficulties." Unfortunately, it is the 100% sliding scale at low levels of interest rates rather than the 80% sliding scale at higher (above 6%) levels of interest rates that is more likely to result in inadequate returns and capital attraction difficulties.

To be able to demonstrate the relationship between interest rates and equity risk premiums with any accuracy, it is necessary to develop a time series of costs of equity which can then be compared with the corresponding yield on long Canada bonds. The form of the equity risk premium test that has been adopted by Canadian regulators[70] does not lend itself to estimating the relationship. The derivation of the results is largely based on the assumption that the equity risk premium is the same at different levels of interest rates, i.e., that there is a one-for-one correlation between the equity market return and the risk-free rate.[71] In other words, the application of the test has generally entailed estimating a long term average market risk premium.

The construction of the DCF-based equity risk premium test, on the other hand, allows the relationship between the utility cost of equity and interest rates to be estimated. As discussed in Section IV.C.4.b, when the utility/government bond yield spread is explicitly accounted for, the relationship between the utility DCF cost of equity and long-term government bond yields has been, on average, an approximately 60 basis point change in the utility cost of equity for every one percentage point change in long-term government bond yields. The estimated relationship implies that the utility cost of equity is less sensitive to changes in government bond yields than implied by the Commission's current automatic

[70] The equity risk premium test that has been widely adopted by Canadian regulators is akin to, or a variant of, the CAPM.
[71] That assumption, however, is in direct conflict with a basic underlying premise of the Capital Asset Pricing Model: the risk-free rate and the expected return on the market are completely uncorrelated.

adjustment formula. In other words, the application of an 80% sliding scale overstates the change in the cost of equity that corresponds to a change in long-term government bond yields.

Focusing specifically on the Canadian equity markets the ratio of the utility dividend yield to the long-term Canada bond yield provides an indicator of the relationship between the utility cost of equity and the long-term government bond yields.

On average over the period 1996-2004, the average ratio of the dividend yields of the six major publicly-traded utilities and pipelines[72] to the long Canada bond yields has been approximately 75% (see Schedule 27). For the dividend to bond yield ratio to remain at 75%, the utility dividend yield must change by 75% of the change in the long Canada bond yield. Using only the change in dividend yields as an indicator of the cost of equity/interest rate relationship ignores any corresponding changes in expected growth rates. Nevertheless, there is no reason to presume that the long-term expected growth rates of utilities vary in a systematic fashion with changes in long term government bond yields. Thus, the relationship between utility dividend yields and long Canada bond yields is itself an indicator of the change in the utility cost of equity due to changes in the risk-free rate.

The 75% "sliding scale" suggested by the dividend yield/bond yield relationship has support from the impact of the different personal taxation rates of dividends, capital gains and interest. Schedule 28 demonstrates that, for a taxable investor, a one percentage point change in the before-tax yield on a long-term Canada bond requires an approximately 70 basis point change in the utility return on equity to maintain a similar after-tax equity risk premium.[73] However, a significant proportion of outstanding utility shares are held by non-taxable investors (e.g.,

[72] Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., Terasen Inc., and TransCanada Corp.
[73] Assuming, as has been the case historically, 40% of the return is dividends and 60% is capital appreciation.

pension funds), and thus do not make investment decisions on the basis of the taxability of various securities. As such, the 70% factor should be interpreted only as a further indicator of the quantitative relationship between the utility cost of equity and long-term Canada bond yields.

I recommend that the Commission implement a symmetric 75% “sliding scale” factor to adjust the allowed return. A factor of 75% recognizes that interest rates and the cost of equity do not rise and fall in tandem; it also recognizes the validity of the objectives of maintaining a stable financial profile, as well as stable rates. The 75% symmetric “sliding scale” will also put the British Columbia utilities on a similar footing to their Canadian peers, the majority of whose returns are governed by symmetric formulas with a 75% sliding scale.[74]

Given the recent low levels of interest rates, and the relative lack of experience with interest rates at this level, I also recommend that the formula should be reviewed if forecast long Canada yields fall below 4% or exceed 8%. Long Canada yields outside of the range of 4.0-8.0% may indicate a materially altered relationship between long Canadas and the utility cost of equity. The 8% ceiling is the same as was adopted by the Commission in its 1999 decision.

The specification of 4% as the bottom end of the range recognizes there has been no experience with long-term Canada yields at or below this level since the 1950s. With respect to the upper end of the range, if long Canadas were to reach 8%, the real cost of capital or inflation would be materially higher than that which is currently anticipated. Both circumstances would warrant a review of the validity of the formula.

[74] The symmetric 75% sliding scale formula has been adopted by the National Energy Board (used since 1995, reconfirmed in 2002); the Ontario Energy Board (since 1997, reconfirmed in 2004); La Régie de L’Energie (adopted in 1998, reconfirmed in 2004); and the Alberta Energy and Utilities Board (adopted in 2004).

APPENDIX A
RISK-ADJUSTED EQUITY MARKT RISK PREMIUM TEST

CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F \quad + \quad \beta(R_M - R_F),}$$

Where:

$\mathbf{R_F}$	=	risk-free rate
$\boldsymbol{\beta}$	=	covariability of the security with the market (M)
$\mathbf{R_M}$	=	return on the market.

The model is based on restrictive assumptions, including:

1. Perfect, or efficient, markets exist where,

   (a) each investor assumes he has no effect on security prices;
   (b) there are no taxes or transaction costs;
   (c) all assets are publicly traded and perfectly divisible;
   (d) there are no constraints on short-sales; and,
   (e) the same risk-free rate applies to both borrowing and lending.

2. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore the shareholder requires no compensation to bear company-specific risks.

DISADVANTAGES OF CAPM

Risk-Free Rate

1. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

   An ROE formula that is premised on a constant equity market risk premium assumes the risk-free rate and the return on the market are perfectly correlated. An ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. For example, the Commission's current formula, which for interest rates below 6%, changes the allowed ROE by 100% of the change in long Canada yields is effectively premised on perfect correlation between the required equity return and the risk-free rate.

2. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

(a) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., as discussed in Section IV.A, the existence of a scarcity premium.

(b) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality" (as discussed in Section IV.A). An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM.

(c) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The ability to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM.

<u>Equity Market Risk Premium</u>

1. The equity market risk premium is typically measured largely by reference to historic data. Adjustments are then made to capture (a) changes that have occurred in the underlying markets over time, or (b) perceived differences between what investors actually achieved and what they may have expected on an *ex ante* basis. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future risk premium. In summary, the link between the historic and the future risk premium is subject to considerable judgement.

2. Canadian historic risk premium data, as discussed in Section IV.A, are problematic. In summary,

   (a) The Canadian equity market has undergone significant structural change over the periods typically used to measure historic risk premiums. The historic premiums reflect in considerable measure a resource-based economy.

   (b) The historic average achieved returns on the TSE 300 Index were significantly affected by the relatively poor performance of commodity-linked securities.

   (c) The TSE 300 Index has been criticized for its lack of liquidity and for the quality and size of the stocks it has contained.

   (d) The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies.

   (e) Despite the structural shift in the TSE Composite away from its historic resource-base, the Canadian market remains significantly less diversified than the U.S. market. Thus, the TSE Composite has, to some extent, had characteristics of a market sector rather than a diversified market portfolio.

   (f) The achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The radical change in Canada's fiscal performance over the past decade, leading to the recent low levels of interest rates, indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns, and therefore understates the future equity risk premium.

Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

1. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

2. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

3. The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market)[1] are a good measure of the relative return requirement.

4. Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

[1] The beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

RELATIONSHIP BETWEEN BETA AND RETURN IN THE CANADIAN EQUITY MARKET

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table A-1

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.054	9%

Source: Schedule 10.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table A-1 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2004, the longest period for which data for the new Composite and its sector components are available; (b) 1988-1997,[2] and (c) the most recent 10-year period ending 2004.

That analysis showed the following:

Table A-2

Returns Measured Over:	Coefficient on Beta	R^2
1988-2004	-.034	15%
1988-1997	-.017	1%
1995-2004	-.066	30%

Source: Schedule 10.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship.

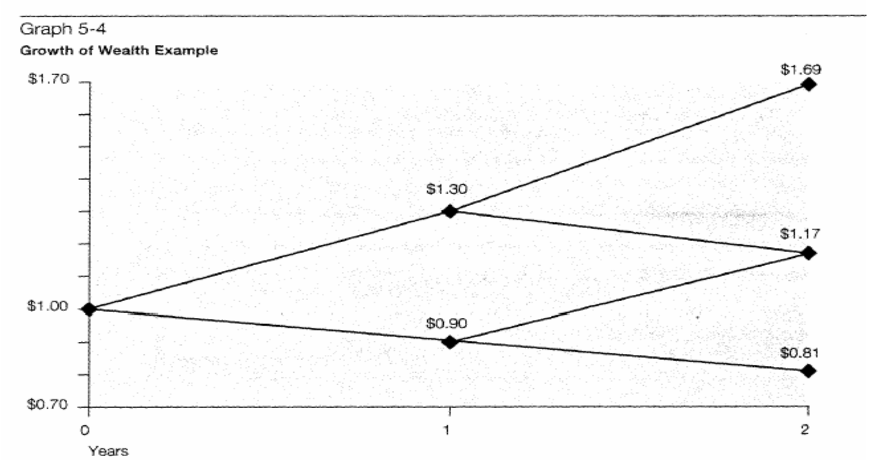
[2] The use of this sub-period was intended to ensure elimination of the impacts of any anomalous market behavior during the technology "bubble" and "bust", which occurred mainly from 1999 through mid-2002.

USE OF ARITHMETIC AVERAGES TO ESTIMATE THE EQUITY MARKET RISK PREMIUM

Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2005,* the following discussion was included:

> "To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year -- +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.



> The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)\text{x}(1-0.10)]^{1/2} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x \$1.69)	=	\$0.4225
+	(0.50 x \$1.17)	=	\$0.5850
+	(0.25 x \$0.81)	=	\$0.2025
	Total		\$1.2100

Therefore, \$1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of \$1.21 after 2 years is 10 percent, the arithmetic mean.

$\$1 \times (1+0.10)^2 = \$1.21$

The geometric mean, when compounded, results in the median of the distribution:

$\$1 \times (1+0.0.082)^2 = \$1.17$

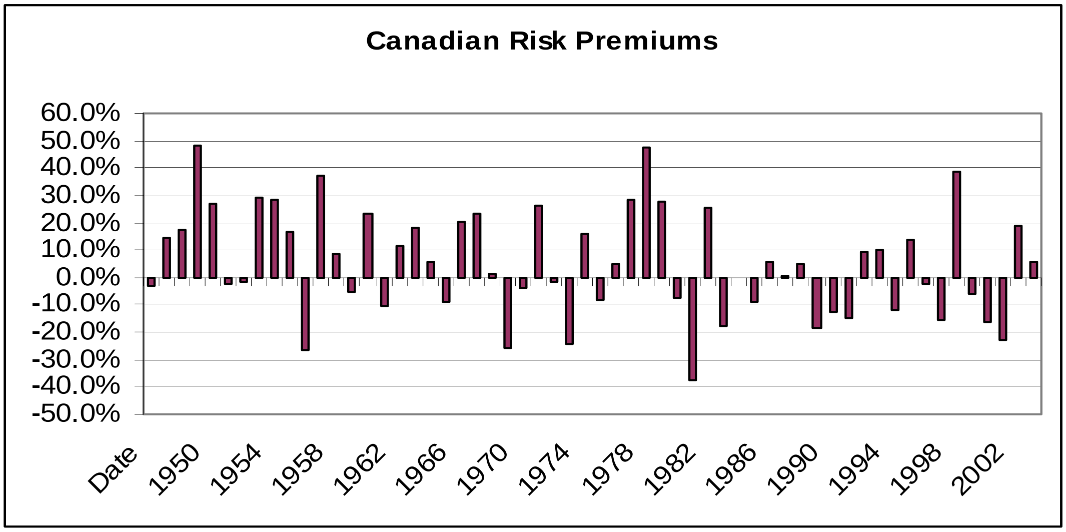
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following graphs illustrate the uncertainty in the future risk premiums by reference to the historic annual risk premiums. The graphs for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[3]

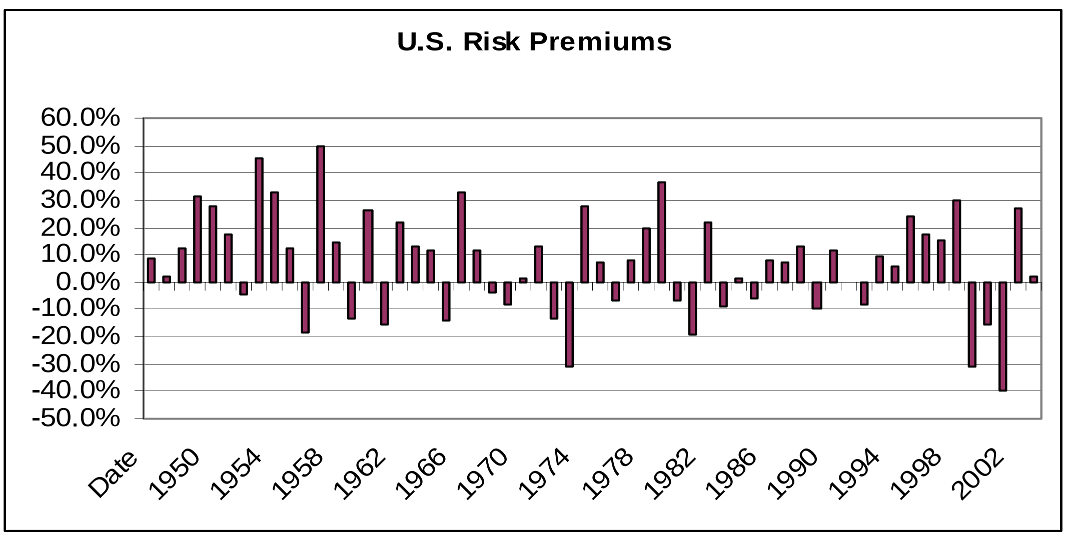
[3] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2004 is .06 for Canada and .05 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium the serial correlation would be close to positive or negative 1.0.

Figure A-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2004.*

Figure A-2



Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2005 Yearbook.*

ANALYSIS OF TRENDS IN CANADIAN AND U.S. STOCK AND BOND RETURNS

Table A-3 below compares the historic Canadian and U.S. stock returns, bond returns, and equity risk premiums, by decade.

Table A-3

Time Period	Stock Returns		Bond Returns		Risk Premiums	
	Canada	U.S.	Canada	U.S.	Canada	U.S.
1940s	10.0%	10.3%	3.9%	3.3%	6.0%	7.0%
1950s	17.0%	20.8%	0.4%	0.0%	16.5%	20.8%
1960s	10.8%	8.7%	2.9%	1.6%	7.9%	7.1%
1970s	12.1%	7.5%	6.1%	5.7%	6.0%	1.8%
1980s	13.1%	18.2%	13.7%	13.5%	-0.6%	4.7%
1990s	11.6%	19.0%	11.8%	9.5%	-0.2%	9.5%
1995-2004	11.2%	14.0%	10.9%	10.4%	0.2%	3.6%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2004*, and Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2005 Yearbook.*

The decade-by-decade averages suggest that there has been no upward or downward trend in the stock returns. By comparison, the bond returns generally exhibit an increase over time. The pattern in the bond returns results from:

(1) low bond returns in the 1950s-1970s, as rising interest rates produced capital losses on bonds;

(2) high bond returns in the 1980s, corresponding to the high rates of inflation, which pushed up bond yields; and,

(3) high bond returns in the 1990s and early 2000s, reflecting the decline in interest rates and resulting capital appreciation of bonds, leading to total returns well in excess of the yields.[4]

A similar conclusion regarding trends in the risk premium can be drawn from an analysis of rolling and cumulative averages of Canadian and U.S. stock and bond returns. The following averages were calculated for this analysis:

(1) Twenty-five year rolling arithmetic averages of Canadian and U.S. equity and long-term government bond returns (1947-2004).

(2) A series of cumulative average equity and bond returns for Canada and the U.S. The first average starts in 1947, covering 25 years (1947-1971). The second average incorporates 26 years, etc. The final average encompasses the full 1947-2004 period.

(3) A second series of cumulative average returns, where the first average includes the most recent 25 year period (1980-2004); each subsequent average includes an additional prior year.

[4] The bond yield is, in fact, an estimate of the expected return.

The following table summarizes the resulting averages for the equity market returns.[5] The summary of the various averages indicates that the historic equity market returns have not exhibited a secular upward or downward trend, but are within the following ranges:

Table A-4

	Canada	U.S.
25-Year Rolling Averages:		
Range	9.6-14.5%	9.4-18.0%
Average of Averages	11.8%	12.4%
± 1 standard deviation	10.7-12.9%	10.3-14.6%
Increasing Averages (1947+):		
Range	11.4-13.6%	11.5-14.6%
Average of Averages	12.6%	13.1%
± 1 standard deviation	12.0-13.1%	12.4-13.9%
Increasing Averages (2003+):		
Range	10.7-12.8%	11.7-14.9%
Average of Averages	11.5%	12.9%
± 1 standard deviation	10.9-12.2 %	11.9-13.9%

Source: Schedule 9.

The analysis also shows achieved total bond returns have experienced an upward trend, similar to that identified in the decade-by-decade returns described earlier. That trend is unlikely to continue, as recent low levels of interest rates limit future capital gains; it is more likely, in an environment of rising interest rates that bonds would experience capital losses, and the achieved risk premiums will rise.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.5%, based on both the Canadian and U.S. equity market returns. Based on the near-term forecast for long Canadas of 5.25%, and an expected equity market return of 11.5-12.5%, the indicated market risk premium would be in the range of 6.25-7.25%, or approximately 6.75%.

[5] All of the averages appear on Schedule 9.

APPENDIX B
DCF-BASED RISK PREMIUM TEST

SELECTION OF PROXY UTILITIES

A sample of U.S. LDCs was selected, comprised of all LDCs satisfying the following criteria:

(1) classified by *Value Line* as a gas distributor;

(2) with no less than 80% of assets (2003) devoted to natural gas distribution operations;

(3) whose Standard & Poor's debt rating is A- or higher; and,

(4) for which, on average over the period of analysis, at least three analysts' long-term earnings growth rate forecasts have been available from the major data base that provides long-term consensus forecasts, i.e., I/B/E/S International, to ensure that the results capture the market view, and not simply the view of a single analyst.

The seven LDCs that met these criteria are listed on Schedule 17.

CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the seven utilities in the sample over the period 1993-2004.[80] The monthly DCF cost for each utility was estimated as the sum of the LDC's I/B/E/S median earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for one-half the I/B/E/S median earnings growth forecast **(DY_e=DY*(1+.5g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCF_s)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERP_s=DCF_s–TY)**. (Schedule 18). The monthly sample average ERP_s were used to estimate the regression equations found in Section IV.C.4.b of the testimony.

[80] Subsequent to Open Access implemented via FERC Order 636.

APPENDIX C
DISCOUNTED CASH FLOW TEST

DCF MODELS

CONSTANT GROWTH MODEL

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries.

Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value. As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not forecast beyond five years. Hence, in that context the current market price and dividend yield would not explicitly anticipate any changes in the outlook for growth.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } \mathbf{(k)} = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[1]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate.

[1]Alternatively expressed as $D_o (1 + g)$, where D_o is the most recently paid dividend.

However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.[2]

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

<u>TWO-STAGE MODEL</u>

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1 Growth), but, in the longer-term (from Year 6 onward) to migrate to the expected long-run rate of growth in the economy (GDP Growth). All industries go through various stages in their life cycle. Utilities are considered to be the quintessential mature industry. Mature industries are those whose growth parallels that of the overall economy.

The use of forecast GDP growth as the long-term growth component is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth in its standard DCF models for gas and oil pipelines.

[2] To illustrate, the average growth rate in dividends forecast by *Value Line* for the proxy sample of utilities for the period through 2008-2010 is 2.8%; the corresponding average *Value Line* forecast of earnings growth for the same period is 4.5%.

Using the two-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor.

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

Cash flows from Year 6 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

SELECTION OF PROXY UTILITIES

A sample of low risk U.S. utilities was selected, comprised of all electric utilities and LDCs, satisfying the following criteria:

(1) Classified by *Value Line* as a gas distributor or an electric utility;

(2) Standard & Poor's business risk profile score of "5" or less;

(3) Standard & Poor's debt rating of A- or higher; and,

(4) For which, on average, over the past 12 months, at least three analysts' long-term earnings forecasts have been available from I/B/E/S.

The 14 utilities that met these criteria are listed on Schedule 19.

INVESTOR GROWTH EXPECTATIONS

The application of the constant growth model relies principally on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S. It also relies on the *Value Line* forecasts of earnings growth as an alternative to the I/B/E/S estimates. The application of the two-stage model relies upon the I/B/E/S consensus earnings forecasts as the estimate of investor growth expectations during Stage 1. The expected long-run rate of growth in the economy (GDP) is based on the consensus of economists' long-term forecasts (published twice annually) found in Blue Chip *Financial Forecasts* (June 1, 2005).

APPLICATION OF THE DCF MODELS

CONSTANT GROWTH MODEL

The constant growth DCF model was applied to the sample of U.S. gas and electric utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of May 31, 2005 as D_o; and,

(2) the average of the high and low monthly prices for the three months ending May 31, 2005 as P_o.

For the expected growth rates, the most recent I/B/E/S (May 2005) consensus (median) earnings growth forecasts and the most recent *Value Line* forecasts of earnings growth[3] were used to estimate "g" in the growth component and to adjust the current dividend yield to the expected dividend yield.

Table C-1 below summarizes the results of the constant growth model.

[3] Estimates issued between April 1, 2005 and June 17, 2005.

Table C-1

Earnings Growth Forecast	**DCF Cost of Equity**	
	Mean	**Median**
I/B/E/S	8.8%	8.8%
Value Line	8.8%	8.8%

Source: Schedules 20 and 21.

TWO-STAGE MODEL

The two-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), and forecast growth in the economy thereafter (Stage 2). The consensus long-run (2007-2016) expected nominal rate of growth in GDP is 5.5%.

The two-stage DCF model estimates of the cost of equity for the utility sample (Schedule 22) are as follows:

Mean	9.7%
Median	9.7%

RESULTS OF THE CONSTANT GROWTH AND TWO-STAGE MODELS

The results of the two models indicate a required "bare-bones" return on equity of in the range of 8.8-9.7%, or approximately 9.25%.

SELECTION OF CANADIAN INDUSTRIALS

The selection process starts with the recognition that industrials are generally exposed to higher business risk, but lower financial risk, than an average risk Canadian utility. The selection of industrials focuses on total investment risk, i.e., the combined business and financial risks. The comparable earnings test is based on the premise that industrials' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting selection of industrial samples of reasonably comparable investment risk to an average risk, or benchmark, Canadian utility.

Utilities are generally characterized by relatively low volatility with respect to both earnings and stock market performance. Consequently, the initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[1] The resulting universe contained 432 firms. From this group of 432 companies, all firms with missing book equity or negative common equity during the period 1993-2003 were removed (64 companies remaining). Next, all companies that paid no dividends in any year 1999-2003 were removed (43 companies remaining). To remove small and/or thinly traded companies, all companies that traded fewer than 125,000 shares in 2003 were eliminated (leaving 41 companies). To ensure that low risk companies were selected, all companies with five-year betas ending 2003 over 1.0 were removed.[2] The resulting group contained 34 companies. Next, those companies whose 1993-2003 returns were greater than ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable. Finally, those companies whose

[1] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

[2] SNC-Lavalin was removed due to its purchase of regulated electric transmission assets in Alberta; Canadian Pacific Railway was also eliminated due to its reorganization in 2000, which rendered its historic data series inconsistent; North West Co. Fund was removed because it is an income trust; Molson was removed due to the company's merger with Coors.

stock was ranked "Higher Risk" or "Speculative" by the Canadian Business Service (CBS),[3] whose debt is rated non-investment grade i.e., BB+ or below by either DBRS or Standard and Poor's, or for which none of the agencies report a rating, were eliminated. The final sample of low risk Canadian industrials is comprised of 17 companies (Schedule 23).

TIME PERIOD FOR MEASURING RETURNS

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., similar in terms of inflation and real economic growth. Over the period 1993-2004, the experienced returns on equity of the sample of 17 industrials were as follows.

Table D-1

Returns on Average Common Equity for Low Risk Canadian Industrials (1993-2004)

Average:	13.6%
Median	13.3%
Average of annual medians:	13.0%

Source: Schedule 24.

Based on these data, the returns are in the approximate range of 13.0-13.5%.

[3] Canadian Business Service (CBS) ranks stocks "Very Conservative", "Conservative", "Average", "Higher Risk", or "Speculative".

The average nominal economic growth during the 1993-2004 cycle was 5.2%, compared to the consensus forecast for real growth of approximately 2.7%, and for inflation (CPI) of 1.9% for the next decade (2005-2015)[4], which suggests nominal long-term GDP growth of approximately 4.6%. With nominal growth expected to be only moderately lower relative to the past business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

RELATIVE RISK COMPARISON

With respect to the relative investment risk of the Canadian industrials compared to an average risk benchmark Canadian utility, the business risk of the industrials exceeds that of utilities; however, this difference is largely offset by the industrials' significantly lower financial risk resulting from higher equity ratios (approximately 66% compared to 40% on average for Canadian utilities; see Schedules 24 and 1).

Comparisons of the industrials' and utilities' bond ratings and stock ratings indicate that they are in a similar risk class. The median CBS stock rating for the industrials is "Very Conservative", equal to the median for a sample of six investor-owned Canadian gas and electric utilities with publicly-traded stock.[5] The median S&P and DBRS debt ratings for the industrials are BBB+ and A(low)/BBB(high) respectively, compared to the major Canadian utilities' median ratings of A- and A (See Schedules 23 and 3). The median adjusted betas for the industrials were 0.48 and 0.56 for the five year periods ending 2003 and 2004 respectively (see Schedule 23), compared to my estimate of the relative risk adjustment factor for a benchmark utility of 0.65.

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[4] Consensus Economics, *Consensus Forecasts*, April 2005.
[5] Canadian Utilities Ltd., Enbridge Inc., Emera Inc., Fortis Inc., Terasen Inc., and TransCanada Corporation.

The estimate of a normal cycle average level of returns for low risk Canadian industrials is in the approximate range of 13.0-13.5%. Since the level of investment risk faced by the industrials is marginally higher than that of an average risk benchmark Canadian utility, a fair return for the latter based on the comparable earnings test is no less than 13.0%.

SELECTION OF U.S. INDUSTRIALS

The U.S. industrials were selected using similar criteria to the selection of Canadian industrials. The initial universe consisted of all firms actively traded in the U.S. from S&P's Compustat database in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[6] The resulting universe contained 2,808 firms. From this group of 2,808 companies, all firms with missing or negative common equity during the period 1993-2003 or with 2003 common equity less than $50 million were removed (770 companies remaining). To ensure that low risk companies were selected, all companies with five-year betas ending 2003 over 1.0 were removed. To remove thinly traded companies, all companies that traded fewer than 125,000 shares in 2003 were eliminated (leaving 527 companies). All non-U.S. companies were then removed, leaving 487. Next, all companies that paid no dividends in any year 1999-2003 were removed (240 companies remaining).[7] Next, those companies whose 1993-2003 returns were greater than ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable. Finally, those companies whose debt is rated non-investment grade i.e., BB+ or below by Standard and Poor's, or for which the *Value Line* Safety

[6] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.
[7] USF, Sears and Molson Coors were removed due to their recent mergers.

Rank was equal to "4" or "5",[8] were eliminated. The final sample of low risk U.S. industrials is comprised of 188 companies (Schedule 25). The returns for the sample of U.S. industrials are summarized in Table D-2 below.

Table D-2

<u>Returns on Average Common Equity for Low Risk U.S. Industrials (1993-2004)</u>	
Average:	14.8%
Median	14.1%
Average of annual medians:	14.6%

Source: Schedule 26.

Based on these data, the returns are in the approximate range of 14.0-14.75%.

As with the Canadian industrials, the business risk of the U.S. industrials exceeds that of utilities; however, this difference is largely offset by the industrials' significantly lower financial risk resulting from higher equity ratios (approximately 75% compared to 40% on average for Canadian utilities; see Schedules 25 and 1).

Comparisons of the industrials' and utilities' bond ratings and stock ratings indicate that they are in a similar risk class. The median *Value Line* Safety Ranking for the U.S. industrials is "3", somewhat weaker than the Safety Ranking of "2" for TransCanada Corporation, the only Canadian regulated firm for which a ranking is provided.[9] The median S&P debt rating for the industrials is A-, identical to the major Canadian utilities'

[8] *Value Line*'s Safety Ranking is a measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other *Value Line* indexes – the Price Stability Index and the Financial strength Rating. Safety Ranks range from "1" (highest) to "5" (lowest).
[9] The average Safety Rank for the proxy samples of U.S. utilities used to perform the DCF-based equity risk premium test and the DCF test is also "2".

median rating of A- (See Schedules 25 and 3). The median adjusted betas for the industrials were 0.66 and 0.67 for the five year periods ending 2003 and 2004 respectively (see Schedule 25), compared to my estimate of the relative risk adjustment factor for a benchmark utility of 0.65.

The returns for the U.S. industrials indicate that the results of the comparable earnings test applied to the Canadian industrials are reasonable.

APPENDIX E
QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is a Senior Vice President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 125 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

APPENDIX E
QUALIFICATIONS OF KATHLEEN C. McSHANE

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- "Utility Cost of Capital Canada vs. U.S.", presented at the CAMPUT Conference, May 2003.
- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several Commissions and Universities, April 1998.
- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

Expert Testimony/Opinions

on

Rate of Return & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002
Ameren (Illinois Power)	2004
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1996
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2002
Hydro One	1999, 2000

Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002
Newfoundland Telephone	1992
Northwestel, Inc.	2000
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001
Nova Scotia Power Inc.	2001, 2002
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions
on
Other Issues

Client	Issue	Date
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

TERASEN GAS INC.
and
TERASEN GAS (VANCOUVER ISLAND) INC.

Statistical Exhibit

to accompany

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
June 2005

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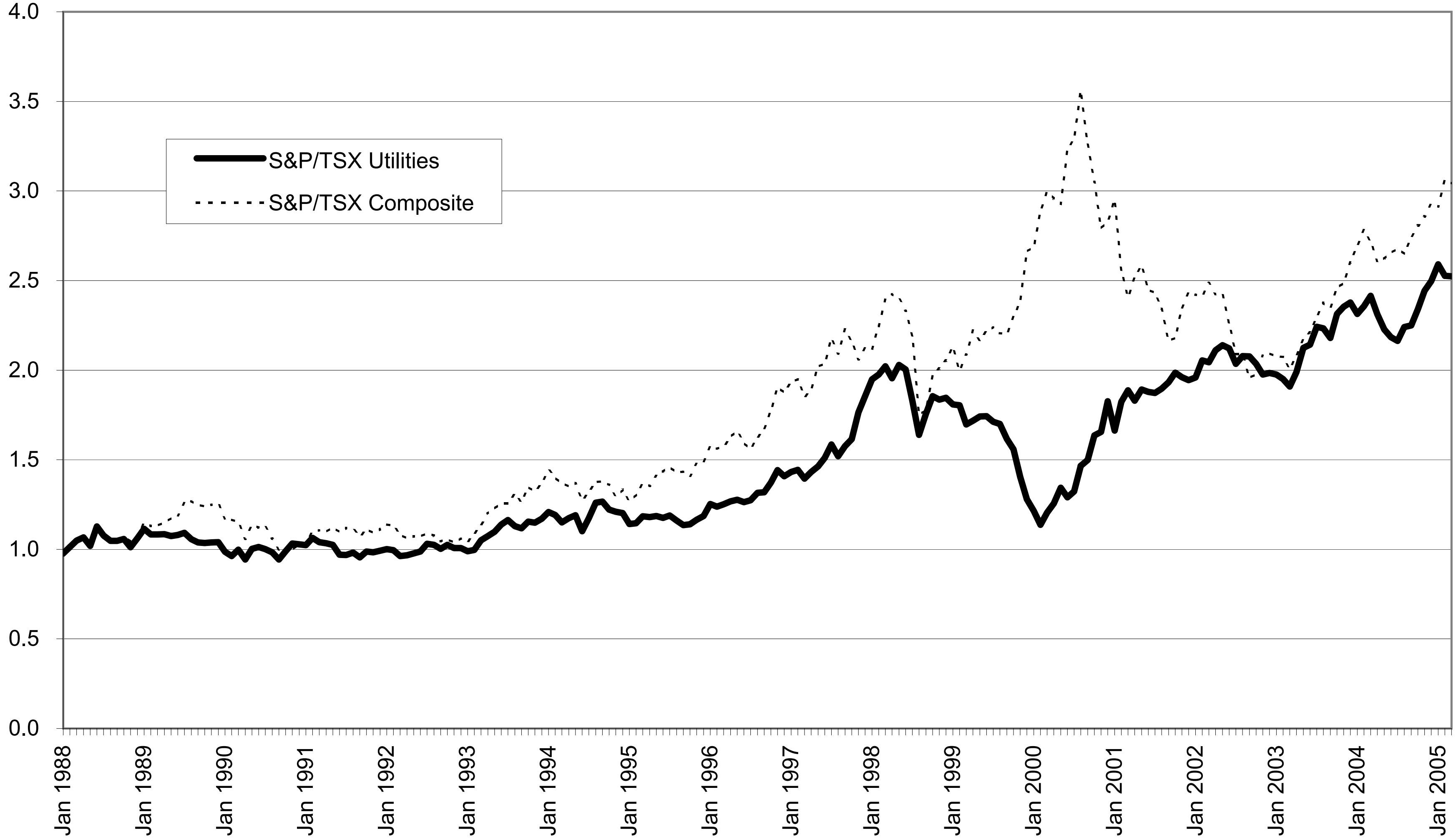
TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
(January 1988 to March 2005)



Source: TSX Review

**CAPITAL STRUCTURE RATIOS
OF MAJOR CANADIAN ELECTRIC AND GAS UTILITIES
(2004)**

Company	Long-term Debt a/	Short-Term Debt	Preferred Stock b/	Common Stock Equity c/
Electric Utilities				
AltaLink L.P.	60.9	0.0	0.0	39.1
CU Inc.	54.7	0.3	6.8	38.3
Epcor Utilities Inc.	44.1	0.0	9.5	46.4
FortisAlberta Inc.	57.1	0.0	0.0	42.9
FortisBC Inc.	59.4	0.0	0.0	40.6
Hydro One Inc.	53.1	0.3	3.3	43.3
Maritime Electric	42.9	10.3	0.0	46.8
Newfoundland Power	46.1	8.2	1.3	44.4
Nova Scotia Power	52.5	0.2	9.4	38.0
Gas Distributors				
Enbridge Gas Distribution	47.1	16.1	2.1	34.7
Gaz Metropolitain	57.0	1.3	0.0	41.7
Pacific Northern Gas	50.2	3.5	2.9	43.3
Terasen Gas	61.3	4.5	0.0	34.2
Union Gas	58.4	4.6	3.1	34.0
Pipelines				
Enbridge Pipelines	51.8	3.6	0.0	44.6
Nova Gas Transmission Ltd.	52.2	10.7	0.0	37.1
TransCanada PipeLines Ltd. d/	56.5	2.9	5.7	34.9
Westcoast Energy Inc.	56.3	2.8	5.2	36.9
Means				
Electric Utilities	**52.3**	**2.1**	**3.4**	**42.2**
Gas Distributors	**54.8**	**6.0**	**1.6**	**37.6**
All Companies	**53.4**	**3.8**	**2.7**	**40.1**

a/ Includes current portion of long-term debt and preferred securities classified as debt.

b/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

c/ Includes minority interest in common shares of subsidiary companies.

d/ Excludes non-recourse debt

Source: Reports to Shareholders, DBRS

PRE-TAX INTEREST COVERAGE RATIOS
FOR MAJOR CANADIAN UTILITIES

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
Electric Utilities									
AltaLink L.P.	na	na	na	na	na	na	na	2.0 [1/]	1.9 [2/]
CU Inc.	3.1	3.2	3.3	3.3	3.1	2.8	2.6	2.8	3.0
FortisAlberta Inc.	na	na	na	na	na	na	2.0	3.0	2.2
FortisBC Inc.	2.5	2.7	2.7	2.2	2.2	2.2	2.4	1.8	2.1
Hydro One Inc. [/3]	na	na	na	na	2.5	2.5	2.6	2.5	3.0
Maritime Electric	3.6	3.1	2.7	2.1	2.3	0.9	2.1	2.2	2.5
Newfoundland Power	2.7	2.8	2.8	2.4	2.5	2.6	2.7	2.6	2.4
Nova Scotia Power	1.8	1.9	2.1	2.1	2.3	2.3	2.3	2.3	2.8
Mean	**2.7**	**2.7**	**2.7**	**2.4**	**2.5**	**2.2**	**2.4**	**2.4**	**2.5**
Median	**2.7**	**2.8**	**2.7**	**2.2**	**2.4**	**2.4**	**2.4**	**2.4**	**2.5**
Gas Distributors									
Enbridge Gas Distribution	2.0	2.6	2.6	2.1	2.2	2.2	2.8	2.7	2.7
Gaz Metropolitain	2.6	2.6	2.7	2.7	2.4	2.7	2.5	2.9	2.9
Pacific Northern Gas	2.1	2.7	2.6	2.3	2.3	2.3	2.3	2.5	2.3
Terasen Gas	1.8	2.0	2.3	2.3	2.3	1.9	1.8	2.0	2.0
Union Gas	2.2	2.3	2.4	2.0	1.8	2.0	1.9	2.1	2.1
Mean	**2.1**	**2.4**	**2.5**	**2.3**	**2.2**	**2.2**	**2.2**	**2.4**	**2.4**
Median	**2.1**	**2.6**	**2.6**	**2.3**	**2.3**	**2.2**	**2.3**	**2.5**	**2.3**
Pipelines									
Enbridge Pipelines (Mainline)	2.5	2.6	2.5	1.7	2.3	2.8	2.8	3.0	3.9
Nova Gas Transmission Ltd.	1.6	1.8	2.1	2.1	2.2	2.3	2.3	2.4	2.4
TransCanada PipeLines Ltd.	1.9	2.0	1.9	1.7	1.7	2.0	2.1	2.3	2.3
Westcoast Energy Ltd.	1.6	1.8	1.8	1.5	1.5	1.7	2.0	2.1	1.9
Mean	**1.9**	**2.0**	**2.1**	**1.7**	**1.9**	**2.2**	**2.3**	**2.5**	**2.6**
Median	**1.8**	**1.9**	**2.0**	**1.7**	**2.0**	**2.2**	**2.2**	**2.3**	**2.4**
All Company Mean	**2.3**	**2.4**	**2.5**	**2.2**	**2.2**	**2.2**	**2.3**	**2.4**	**2.5**
All Company Median	**2.1**	**2.6**	**2.5**	**2.1**	**2.3**	**2.3**	**2.3**	**2.4**	**2.4**

/1 12 months ended April 2003
/2 12 months ended April 2004
/3 Post restructuring

Source: DBRS Inc., Annual Report to Shareholders (Maritime Electric).

DEBT AND COMMON STOCK QUALITY RATINGS
OF MAJOR CANADIAN GAS AND ELECTRIC UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
AltaLink L.P.	Senior Secured	A(high)		A-	NR
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
Epcor Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	NR
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa3		Very conservative
Gaz Metropolitain	Senior Secured	A		A	NR
Hydro One	Senior Unsecured	A	A2	A	NR
Maritime Electric	Senior Secured	NR		BBB+	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB+	Very conservative
Pacific Northern Gas	Senior Secured	BBB(low)		NR [1/]	Average
Terasen Gas	Senior Secured Senior Unsecured	A A	A1 A2	A- BBB	Very conservative
TransCanada PipeLines	Senior Unsecured	A	A2	A-	Very conservative
Union Gas Limited	Senior Unsecured	A		BBB	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB	Very conservative
Median		**A**	**A3**	**A-**	**Very conservative**

1/ Withdrawn by company; BB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

STANDARD & POOR'S DEBT RATINGS, BUSINESS RISK PROFILE SCORES, DEBT AND INTEREST COVERAGE RATIOS FOR U.S. A-RATED LDCs

	S&P Debt Rating	Business Profile	FFO Interest Coverage (x)	FFO/ Avg. Total Debt (%)	Total Debt/Capital (%)
Nicor Inc.	AA	3	5.9	43.1	54.6
Washington Gas Light Co.	AA-	2	4.6	23.7	48.5
WGL Holdings Inc.	AA-	3	4.7	22.5	49.2
New Jersey Natural Gas Co.	A+	2	5.4	19.1	55.3
Northwest Natural Gas Co.	A+	1	4.1	21.1	52.8
KeySpan Corp.	A	4	4.1	17.3	63.6
Laclede Group Inc. (The)	A	3	3.2	12.7	61.0
Piedmont Natural Gas Co. Inc.	A	2	3.5	17.2	55.1
Southern California Gas Co.	A	1	7.9	52.1	44.2
AGL Resources Inc.	A-	4	3.3	17.9	62.3
Alabama Gas Corp.	A-	2	4.9	30.8	47.8
Equitable Resources Inc.	A-	7	6.5	33.3	46.5
Indiana Gas Co. Inc.	A-	1	3.4	14.1	58.5
North Shore Gas Co.	A-	2	5.7	31.1	40.6
Pivotal Utility Holdings (NUI Utilities)	A-	4	3.7	14.2	68.1
Peoples Energy Corp.	A-	5	4.4	20.2	56.6
Peoples Gas Light & Coke Co. (The)	A-	2	5.6	22.5	49.8
Public Service Co. of North Carolina Inc.	A-	2	4.5	29.3	25.1
Questar Gas Co.	A-	3	3.8	19.7	52.8
Wisconsin Gas Co.	A-	2	6.9	25.1	34.7
Mean All Companies	**A**	**3**	**4.8**	**24.3**	**51.4**
Median All Companies	**A-**	**2**	**4.5**	**21.8**	**52.8**

Source: S&P "U.S. Utility and Power Ranking List" (June 17, 2005); and the following S&P Credit Stats (August 2004) tables:

Energy Utilities--Diversified
Gas Distribution Utilities--Integrated
Gas Transmission & Distribution Utilities--Regulated

STANDARD & POOR'S DEBT RATINGS, BUSINESS RISK PROFILE SCORES, DEBT AND INTEREST COVERAGE RATIOS FOR U.S. A-RATED REGULATED ELECTRIC TRANSMISSION, DISTRIBUTION AND COMBINATION UTILITIES

	S&P Debt Rating	Business Profile	FFO Interest Coverage (x)	FFO/ Avg. Total Debt (%)	Total Debt/Capital (%)
Boston Edison Co.	A	1	5.3	25.5	55.0
Central Hudson Gas & Electric Corp.	A	3	4.0	28.0	47.8
Consolidated Edison Co. of New York Inc.	A	2	3.1	16.7	54.9
Consolidated Edison Inc.	A	2	3.2	16.6	54.6
NSTAR	A	1	3.7	17.4	62.3
New England Power Co.	A	1	12.8	38.3	30.4
Orange and Rockland Utilities Inc.	A	2	4.0	22.2	51.9
San Diego Gas & Electric Co.	A	5	4.1	21.7	54.1
Central Illinois Light Co.	A-	5	5.4	27.1	49.3
Central Illinois Public Service Co.	A-	3	2.9	12.0	48.8
CILCORP Inc.	A-	5	2.2	9.7	60.5
Commonwealth Edison Co.	A-	4	3.4	22.5	49.8
Illinois Power Co.	A-	4	2.9	12.8	59.2
PECO Energy Co.	A-	4	4.0	22.8	85.1
PPL Electric Utilities Corp.	A-	4	2.6	10.8	55.2
Mean All Companies	**A/A-**	**3**	**4.2**	**20.3**	**54.6**
Median All Companies	**A**	**3**	**3.7**	**21.7**	**54.6**

Source: S&P "U.S. Utility and Power Ranking List" (June 17, 2005); and the following S&P Credit Stats (August 2004) tables:

Electric & Gas Transmission & Distribution Utilities--Regulated
Electric Transmission & Distribution Utilities--Regulated
Electric Transmission & Transport Utilities--Regulated

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date	Order/ File Number	Debt	Preferred Stock	Common Stock Equity		Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)		(6)	(7)	
Electric Utilities									
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00	a/	9.50	5.55	
ATCO Electric									
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00		9.50	5.55	
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00		9.50	5.55	
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00		9.50	5.55	
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00		9.43	5.53	
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55		9.24	4.96	
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50		9.55	na	b/
Gas Distributors									
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00		9.50	5.55	
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61.91	3.09	35.00		9.57	5.81	
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50		9.69	5.80	c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00		9.80	5.65	d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00		9.03	5.53	
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61.50	3.50	35.00		9.62	5.68	
Gas Pipelines									
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Foothills Pipe Lines (Yukon) Ltd.	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00		9.46	5.55	
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00		9.46	5.55	

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1.95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Electric Utilities																
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	a/	a/	a/	a/	a/	a/	9.40	9.60	9.50
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	a/	b/	9.25	9.25	NA	9.40	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**	**9.53**	**9.57**	**9.62**	**9.45**
Gas Distributors																
Atco Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50
Centra Gas Ontario	13.50	13.75	13.50	12.50	11.85	12.13	NA	11.25	10.69	c/	c/	c/	c/	c/	c/	c/
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	d/
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	NA	NA	9.62	9.62
Mean of Gas Distributors	**13.83**	**13.65**	**13.13**	**12.51**	**11.68**	**12.05**	**11.68**	**11.00**	**10.33**	**9.60**	**9.83**	**9.68**	**9.62**	**9.73**	**9.50**	**9.48**
Gas Pipelines (NEB)																
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**
Mean of All Companies	**13.66**	**13.58**	**12.99**	**12.19**	**11.54**	**12.13**	**11.36**	**10.88**	**10.20**	**9.52**	**9.78**	**9.67**	**9.57**	**9.68**	**9.56**	**9.47**

Note: A rate freeze was in effect for BC Gas (now Terasen Gas) in 1990 and 1991, BCUC regulation resumed in late 1991.
Nova Scotia Power was privatized in 1992.

a/ Negotiated settlement, details not available.
b/ Negotiated settlement, implicit ROE made public is 10.5%.
c/ Merged with Union Gas.
d/ 2005 rate application currently pending.

Source: Regulatory Decisions

**COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS
FOR CANADIAN AND U.S. UTILITIES**

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.66	10.69	2.97	12.69	8.61	4.08
1991	13.58	9.72	3.87	12.51	8.14	4.37
1992	12.99	8.68	4.37	12.06	7.67	4.39
1993	12.19	7.86	4.30	11.37	6.59	4.78
1994	11.54	8.69	2.88	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.88	6.66	4.22	11.34	6.58	4.76
1998	10.20	5.59	4.61	11.59	5.54	6.05
1999	9.52	5.72	3.80	10.74	5.91	4.83
2000	9.78	5.71	4.07	11.41	5.88	5.53
2001	9.67	5.77	3.90	11.04	5.50	5.54
2002	9.57	5.67	3.92	11.10	5.41	5.69
2003	9.68	5.31	4.37	10.98	5.03	5.95
2004	9.56	5.11	4.45	10.73	5.08	5.65
2005 [a/]	9.47	4.72	4.75	10.48	4.70	5.78
Means:						
1990-1993	**13.10**	**9.24**	**3.88**	**12.16**	**7.75**	**4.41**
1994-1998	**11.22**	**7.42**	**3.81**	**11.41**	**6.62**	**4.80**
1999-2005Q1	**9.60**	**5.43**	**4.18**	**10.93**	**5.36**	**5.57**

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 forward.

a/ Includes all U.S. returns determined in the first quarter of 2005.

Sources: Regulatory Focus, Regulatory Research Associates; Various Canadian Regulatory Decisions; Bank of Canada; Federal Reserve, U.S. Treasury.

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada					United States				
		Gross Domestic Product			GDP	Consumer	Gross Domestic Product			Implicit	Consumer
		Constant	Current	Industrial	Deflator	Price	Constant	Current	Industrial	Price	Price
Year		Dollars	Dollars	Production	Index	Index	Dollars	Dollars	Production	Index a/	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(I0)
1989		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.2	104.8	101.9	105.8	100.9	103.9	105.4
1991		98.1	104.2	93.5	106.2	110.7	101.7	109.3	99.4	107.5	109.8
1992		99.0	106.5	94.5	107.6	112.3	105.1	115.6	102.2	110.0	113.2
1993		101.3	110.6	98.8	109.2	114.4	107.9	121.4	105.6	112.5	116.5
1994		106.1	117.2	105.1	110.4	114.6	112.2	129.0	111.3	114.9	119.5
1995		109.1	122.7	109.9	112.9	117.1	115.0	134.9	116.6	117.2	122.9
1996		110.9	126.8	111.8	114.7	118.9	119.3	142.5	121.6	119.5	126.5
1997		115.6	133.5	118.0	116.1	120.8	124.7	151.4	130.4	121.5	129.5
1998		120.3	139.2	122.2	115.6	122.0	129.9	159.5	138.0	122.8	131.5
1999		127.0	149.4	129.8	117.6	124.1	135.7	169.0	144.2	124.6	134.4
2000		133.6	163.5	139.1	122.5	127.5	140.6	179.0	150.5	127.3	138.9
2001		136.0	168.5	135.1	123.9	130.8	141.7	184.7	145.1	130.4	142.8
2002		140.7	176.1	137.8	125.1	133.7	144.3	191.2	144.7	132.5	145.1
2003		143.5	185.3	138.7	129.1	137.4	148.7	200.6	144.7	134.9	148.4
2004		147.5	196.6	143.2	133.3	139.9	155.3	214.0	150.7	137.8	152.3
2001	1Q	135.6	169.6	137.1	125.1	129.4	141.5	182.7	147.7	129.2	141.7
	2Q	135.8	169.9	136.5	125.1	131.5	141.9	184.7	145.9	130.2	143.2
	3Q	135.6	167.5	134.0	123.5	131.6	141.4	184.8	144.2	130.7	143.4
	4Q	137.0	167.0	132.8	122.0	130.5	141.9	186.5	142.6	131.4	143.0
2002	1Q	138.8	170.5	135.5	122.9	131.3	143.1	188.5	143.4	131.7	143.5
	2Q	140.1	175.4	137.9	125.2	133.3	144.0	190.5	145.0	132.3	145.0
	3Q	141.6	177.7	139.2	125.6	134.7	144.9	192.3	145.6	132.7	145.6
	4Q	142.2	180.5	138.6	126.9	135.4	145.2	193.6	144.8	133.4	146.1
2003	1Q	143.2	184.7	139.3	129.0	137.2	145.9	195.9	144.5	134.3	147.6
	2Q	142.9	183.5	137.3	128.5	137.0	147.4	198.5	143.1	134.7	148.1
	3Q	143.4	185.4	138.1	129.3	137.6	150.0	202.7	144.5	135.1	148.8
	4Q	144.6	187.6	140.1	129.7	137.8	151.6	205.5	146.5	135.6	148.9
2004	1Q	145.6	190.8	140.7	131.0	138.4	153.2	209.2	148.6	136.5	150.2
	2Q	147.2	195.6	142.6	132.9	140.0	154.5	212.6	150.1	137.6	152.4
	3Q	148.3	198.9	144.5	134.1	140.3	156.0	215.4	151.1	138.1	152.9
	4Q	148.9	201.3	145.0	135.2	140.9	157.5	218.7	152.8	138.9	153.8

Note: Data are based on Chain Weighted Indexes.

Source: Statistics Canada; U.S. Bureau of Economic Analysis, Federal Reserve Statistics Survey of Current Business.

Tab 2
SCHEDULE 6
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TREND IN AFTER-TAX CORPORATE PROFITS
IN CANADA AND THE UNITED STATES

		Canada		United States	
Year		Millions of Dollars a/	As Percent of GDP	Billions of Dollars	As Percent of GDP
		(1)	(2)	(3)	(4)
1989		41,095	5.4%	237.7	4.3%
1990		28,102	3.7%	264.1	4.6%
1991		17,905	2.4%	284.4	4.7%
1992		18,131	2.4%	312.4	4.9%
1993		24,839	3.2%	346.1	5.2%
1994		46,122	5.7%	383.3	5.4%
1995		54,132	6.5%	455.6	6.2%
1996		54,096	6.4%	501.4	6.4%
1997		55,682	6.3%	552.1	6.6%
1998		55,332	6.0%	470.0	5.4%
1999		71,359	7.3%	517.2	5.6%
2000		87,803	8.6%	508.2	5.2%
2001		88,894	8.6%	495.6	4.9%
2002		99,540	9.3%	549.9	5.2%
2003		106,655	9.7%	631.5	5.7%
2004		126,083	11.2%	716.2	6.1%
2001	1Q	97,152	9.4%	532.1	5.3%
	2Q	95,000	9.2%	537.1	5.3%
	3Q	84,484	8.2%	473.6	4.7%
	4Q	78,940	7.5%	472.4	4.6%
2002	1Q	88,712	8.4%	526.9	5.1%
	2Q	99,432	9.3%	562.4	5.4%
	3Q	104,596	9.7%	584.8	5.5%
	4Q	105,420	9.7%	622.7	5.9%
2003	1Q	114,160	10.4%	602.1	5.6%
	2Q	100,000	9.2%	600.0	5.5%
	3Q	103,764	9.5%	642.3	5.8%
	4Q	108,696	9.8%	713.9	6.3%
2004	1Q	117,984	10.6%	705.9	6.2%
	2Q	127,200	11.3%	717.1	6.2%
	3Q	128,852	11.4%	679.5	5.8%
	4Q	130,296	11.5%	762.1	6.4%

a/ Corporation profits before taxes less direct taxes (corporate and government business enterprises - Total).

Source: Statistics Canada, U.S. Bureau of Economic Analysis

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		T-BILLS Canadian	T-BILLS U.S. a/	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. b/	Canada Bonds Over 10 Years c/	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates	Canadian A-Rated Utility Bonds d/	Exchange Rates (Canadian dollars in U.S. funds)
1993	q1	5.84	2.96	7.65	6.28	8.27	6.98	8.38	4.57	9.54	9.54	0.79
	q2	4.91	3.01	7.46	5.99	8.11	6.87	8.12	4.39	9.16	9.35	0.79
	q3	4.52	3.02	6.99	5.62	7.63	6.29	7.58	4.21	8.50	8.84	0.77
	q4	4.11	3.09	6.76	5.61	7.42	6.19	7.31	3.94	8.20	8.58	0.75
1994	q1	4.29	3.42	7.09	6.07	7.67	6.74	7.48	3.80	8.33	8.79	0.75
	q2	6.28	3.96	8.49	7.08	8.69	7.33	8.67	4.38	9.52	10.09	0.72
	q3	5.48	4.61	8.99	7.33	9.13	7.55	9.14	4.67	9.92	10.11	0.73
	q4	6.11	5.36	9.12	7.84	9.25	7.94	9.23	4.80	10.00	10.24	0.73
1995	q1	7.99	5.73	8.89	7.48	9.01	7.61	8.99	4.86	9.80	9.99	0.71
	q2	7.34	5.58	8.00	6.62	8.32	6.91	8.19	4.48	8.93	9.38	0.73
	q3	6.47	5.32	8.05	6.32	8.45	6.71	8.28	4.76	8.97	9.30	0.74
	q4	5.76	5.15	7.39	5.89	7.85	6.18	7.66	4.61	8.37	8.44	0.74
1996	q1	5.11	4.92	7.39	5.91	7.95	6.37	7.71	4.78	8.40	8.41	0.73
	q2	4.70	5.04	7.75	6.72	8.17	6.95	7.99	4.87	8.60	8.58	0.73
	q3	4.14	5.13	7.37	6.78	7.88	7.00	7.65	4.71	8.22	8.23	0.73
	q4	2.89	5.08	6.30	6.34	6.99	6.60	6.67	4.07	7.23	7.19	0.74
1997	q1	2.96	5.11	6.54	6.64	7.24	6.91	6.94	4.19	7.50	7.52	0.74
	q2	3.00	5.12	6.49	6.64	7.03	6.90	6.80	4.26	7.28	7.30	0.72
	q3	3.18	5.06	5.85	6.18	6.39	6.45	6.16	4.06	6.64	6.59	0.72
	q4	3.89	5.14	5.55	5.84	5.98	6.07	5.79	4.07	6.38	6.34	0.71
1998	q1	4.44	5.08	5.41	5.63	5.76	5.93	5.60	4.07	6.25	6.22	0.70
	q2	4.82	4.99	5.39	5.58	5.63	5.80	5.53	3.90	6.09	6.05	0.69
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	0.65
1999	q1	4.73	4.41	5.07	5.03	5.34	5.41	5.23	4.13	6.13	6.15	0.66
	q2	4.55	4.53	5.34	5.56	5.54	5.80	5.50	4.07	6.40	6.34	0.68
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	0.65
2000	q1	5.09	5.59	6.22	6.38	5.98	6.16	6.10	3.91	7.14	7.07	0.69
	q2	5.54	5.68	6.01	6.18	5.72	5.96	5.96	3.74	7.21	7.05	0.68
	q3	5.58	6.05	5.79	5.86	5.58	5.78	5.82	3.64	7.07	7.09	0.67
	q4	5.57	6.09	5.54	5.46	5.56	5.62	5.67	3.48	7.10	7.15	0.65
2001	q1	4.96	4.64	5.44	5.01	5.76	5.45	5.69	3.41	7.05	7.18	0.65
	q2	4.36	4.42	5.78	5.40	5.95	5.77	6.00	3.56	7.25	7.40	0.65
	q3	3.64	3.10	5.48	4.84	5.82	5.44	5.86	3.67	7.13	7.24	0.64
	q4	2.11	1.86	5.22	4.72	5.53	5.32	5.58	3.68	6.95	7.20	0.63
2002	q1	2.10	1.78	5.52	5.12	5.78	5.66	5.81	3.71	6.97	7.23	0.63
	q2	2.57	1.74	5.51	5.02	5.83	5.72	5.81	3.52	6.99	7.14	0.65
	q3	2.83	1.66	5.07	4.09	5.56	5.13	5.52	3.36	7.01	7.26	0.63
	q4	2.69	1.33	4.98	3.99	5.48	5.11	5.45	3.39	6.95	7.23	0.64
2003	q1	2.96	1.17	5.01	3.85	5.49	4.93	5.43	3.09	6.92	7.22	0.67
	q2	3.14	1.05	4.59	3.60	5.17	4.71	5.09	3.04	6.42	6.72	0.72
	q3	2.70	0.96	4.75	4.30	5.30	5.28	5.26	3.11	6.40	6.69	0.72
	q4	2.62	0.95	4.78	4.31	5.29	5.22	5.24	2.90	6.24	6.47	0.77
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	5.92	6.17	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.25	6.48	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.19	6.37	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	5.90	6.09	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.67	5.86	0.82
Annual												
	1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		11.91	12.13	0.86
	1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		10.80	11.00	0.84
	1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	9.90	10.01	0.82
	1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	8.85	9.08	0.77
	1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.44	9.81	0.73
	1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.02	9.29	0.73
	1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.11	8.38	0.73
	1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	6.95	7.19	0.72
	1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.22	6.38	0.68
	1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.64	6.92	0.67
	2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.13	7.02	0.67
	2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.09	7.25	0.65
	2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	6.98	7.22	0.64
	2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.50	6.78	0.72
	2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.06	6.28	0.77

(Columns T-BILLS through Canadian Inflation Indexed Bonds are grouped under "Government Securities".)

a/ Rates on new issues.
b/ 20-year constant maturities for 1974-1978; 30-year maturities, 1978-January 2002. Theoretical 30-year yield, February 2002 forward.
c/ Terms to maturity of l0 years or more.
d/ Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: Bank of Canada Review; CBRS; Globe and Mail; Annual Statistical Digest (Federal Reserve System); Federal Reserve Bulletin (various issues), U.S. Treasury website.

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		Government Securities										
		T-BILLS		10 Year		Long-Term		Canada Bonds Over 10 Years c/	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates	Canadian A-Rated Utility Bonds d/	Exchange Rates (Canadian dollars in U.S. funds)
Year		Canadian	U.S. a/	Canadian	U.S.	Canadian	U.S. b/					
2003	Jan	2.82	1.18	5.02	4.00	5.47	4.99	5.43	3.21	6.85	7.13	0.66
	Feb	2.92	1.20	4.94	3.71	5.44	4.82	5.38	3.00	6.81	7.17	0.67
	Mar	3.14	1.14	5.08	3.83	5.55	4.98	5.48	3.05	7.09	7.35	0.68
	Apr	3.19	1.13	4.90	3.89	5.41	4.93	5.34	3.13	6.70	6.96	0.70
	May	3.17	1.11	4.41	3.37	5.00	4.50	4.89	2.96	6.35	6.64	0.73
	June	3.07	0.90	4.45	3.54	5.09	4.70	5.04	3.04	6.22	6.57	0.74
	July	2.85	0.96	4.84	4.49	5.44	5.51	5.39	3.17	6.48	6.85	0.71
	Aug	2.68	0.98	4.86	4.45	5.35	5.31	5.31	3.12	6.54	6.76	0.72
	Sept	2.58	0.95	4.55	3.96	5.14	5.01	5.09	3.03	6.19	6.45	0.74
	Oct	2.64	0.96	4.83	4.33	5.35	5.25	5.30	3.00	6.39	6.65	0.76
	Nov	2.66	0.93	4.84	4.34	5.33	5.22	5.28	2.92	6.27	6.51	0.77
	Dec	2.57	0.95	4.66	4.27	5.20	5.18	5.14	2.79	6.07	6.26	0.77
2004	Jan	2.25	0.92	4.53	4.16	5.17	5.07	5.09	2.59	6.03	6.26	0.76
	Feb	2.12	0.96	4.36	3.99	5.05	4.95	4.94	2.52	5.87	6.13	0.75
	Mar	1.98	0.95	4.33	3.86	5.04	4.87	4.94	2.39	5.85	6.11	0.76
	Apr	1.92	0.98	4.62	4.53	5.24	5.36	5.15	2.46	6.15	6.41	0.73
	May	2.00	1.08	4.78	4.66	5.31	5.29	5.22	2.31	6.25	6.43	0.73
	June	2.01	1.33	4.83	4.62	5.33	5.41	5.30	2.37	6.36	6.60	0.75
	Jul	2.07	1.45	4.75	4.50	5.24	5.31	5.24	2.31	6.34	6.49	0.75
	Aug	2.17	1.59	4.60	4.13	5.09	4.97	5.08	2.24	6.17	6.33	0.76
	Sep	2.44	1.71	4.63	4.14	5.08	4.97	5.06	2.33	6.05	6.29	0.79
	Oct	2.57	1.91	4.47	4.05	4.94	4.87	4.91	2.26	5.99	6.17	0.82
	Nov	2.55	2.23	4.44	4.36	4.98	5.07	4.93	2.21	5.88	6.16	0.84
	Dec	2.48	2.22	4.30	4.24	4.83	4.86	4.77	2.07	5.82	5.94	0.83
2005	Jan	2.43	2.51	4.21	4.14	4.71	4.62	4.67	2.03	5.66	5.84	0.81
	Feb	2.46	2.76	4.28	4.36	4.75	4.71	4.71	2.09	5.62	5.86	0.81
	Mar	2.52	2.73	4.32	4.50	4.71	4.76	4.68	2.03	5.73	5.87	0.83
	Apr	2.45	2.90	4.14	4.21	4.58	4.53	4.54	1.90	5.04	5.79	0.80
	May	2.45	2.99	3.92	4.00	4.37	4.36	4.31	1.83	5.46	5.59	0.80

a/ Rates on new issues.
b/ 20-year constant maturities for 1974-1978; 30-year maturities, 1978-January 2002. Theoretical 30-year yield, February 2002 forward.
c/ Terms to maturity of l0 years or more.
d/ Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000;
a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.
Note: Monthly data reflect rate in effect at end of month.

Source: Bank of Canada Review; CBRS; Globe and Mail; Annual Statistical Digest (Federal Reserve System);
Federal Reserve Bulletin (various issues), U.S. Treasury website.

HISTORIC EQUITY MARKET RISK PREMIUMS

Canada
(1947-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.1	6.9	5.3
Geometric	10.9	6.4	4.5

United States
(1947-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	13.2	6.3	7.0
Geometric	11.9	5.8	6.2

United Kingdom
(1947-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	14.9	8.9	6.0
Geometric	11.9	6.3	5.6

Source: Ibbotson Associates: Stocks, Bonds, Bills and Inflation: 2005 Yearbook Market Results 1924-2004; Standardandpoors.com; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2004; TSX.com; and Barclays, Equity Gilt Study.

25-YEAR ROLLING AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.9%	13.7%	2.0%
1948-1972	13.8%	2.8%	14.3%	2.3%
1949-1973	13.3%	3.0%	13.5%	2.1%
1950-1974	11.3%	2.7%	11.7%	2.0%
1951-1975	10.1%	2.8%	11.9%	2.4%
1952-1976	9.6%	3.7%	11.9%	3.2%
1953-1977	10.1%	3.9%	10.8%	3.2%
1954-1978	11.2%	3.8%	11.1%	3.0%
1955-1979	11.4%	3.3%	9.8%	2.6%
1956-1980	11.5%	3.4%	9.8%	2.5%
1957-1981	10.6%	3.4%	9.4%	2.8%
1958-1982	11.6%	4.9%	10.6%	4.1%
1959-1983	11.8%	5.5%	9.8%	4.4%
1960-1984	11.5%	6.3%	9.6%	5.1%
1961-1985	12.4%	7.0%	10.8%	5.8%
1962-1986	11.5%	7.3%	10.5%	6.7%
1963-1987	12.0%	7.2%	11.1%	6.4%
1964-1988	11.8%	7.4%	10.8%	6.7%
1965-1989	11.6%	7.8%	11.4%	7.3%
1966-1990	10.8%	7.9%	10.8%	7.5%
1967-1991	11.5%	8.8%	12.4%	8.1%
1968-1992	10.8%	9.4%	11.8%	8.8%
1969-1993	11.2%	10.4%	11.7%	9.6%
1970-1994	11.2%	10.0%	12.1%	9.4%
1971-1995	11.9%	10.2%	13.5%	10.2%
1972-1996	12.7%	10.3%	13.8%	9.7%
1973-1997	12.2%	11.0%	14.4%	10.1%
1974-1998	12.2%	11.5%	16.1%	10.6%
1975-1999	14.5%	11.3%	18.0%	10.1%
1976-2000	14.0%	11.7%	16.2%	10.6%
1977-2001	13.1%	11.1%	14.7%	10.1%
1978-2002	12.2%	11.3%	14.1%	10.8%
1979-2003	12.0%	11.5%	15.0%	10.9%
1980-2004	**10.8%**	**12.0%**	**14.7%**	**11.3%**
Min	**9.6%**	**2.7%**	**9.4%**	**2.0%**
Max	**14.5%**	**12.0%**	**18.0%**	**11.3%**
Mean	**11.8%**	**7.3%**	**12.4%**	**6.5%**
Stdev.	**1.1%**	**3.4%**	**2.2%**	**3.4%**
+1 Std	**12.9%**	**10.6%**	**14.6%**	**9.9%**
-1 Std dev.	**10.7%**	**3.9%**	**10.3%**	**3.2%**

Source: Ibbotson Associates: Stocks, Bonds, Bills and Inflation: 2005 Yearbook Market Results 1924-2004, Standardandpoors.com; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2004; and TSX.com

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(1947 Forward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.8%	13.7%	2.0%
1947-1972	13.2%	2.8%	13.9%	2.1%
1947-1973	12.8%	2.6%	12.9%	2.0%
1947-1974	11.4%	2.6%	11.5%	2.1%
1947-1975	11.6%	3.2%	12.4%	2.3%
1947-1976	11.6%	3.3%	12.7%	2.8%
1947-1977	11.6%	3.2%	12.1%	2.7%
1947-1978	12.1%	3.0%	11.9%	2.6%
1947-1979	13.1%	3.0%	12.1%	2.5%
1947-1980	13.6%	2.8%	12.7%	2.3%
1947-1981	12.9%	3.9%	12.2%	2.3%
1947-1982	12.7%	4.1%	12.5%	3.3%
1947-1983	13.4%	4.4%	12.7%	3.2%
1947-1984	12.9%	4.9%	12.6%	3.6%
1947-1985	13.3%	5.2%	13.1%	4.3%
1947-1986	13.1%	5.1%	13.2%	4.8%
1947-1987	13.0%	5.2%	13.0%	4.6%
1947-1988	12.9%	5.5%	13.1%	4.7%
1947-1989	13.1%	5.4%	13.5%	5.0%
1947-1990	12.5%	5.9%	13.2%	5.0%
1947-1991	12.5%	6.0%	13.5%	5.4%
1947-1992	12.2%	6.4%	13.4%	5.4%
1947-1993	12.6%	6.0%	13.3%	5.7%
1947-1994	12.3%	6.4%	13.1%	5.4%
1947-1995	12.4%	6.6%	13.6%	6.0%
1947-1996	12.7%	6.8%	13.8%	5.8%
1947-1997	12.7%	7.0%	14.2%	6.0%
1947-1998	12.5%	6.7%	14.4%	6.1%
1947-1999	12.8%	6.8%	14.6%	5.9%
1947-2000	12.7%	6.8%	14.1%	6.1%
1947-2001	12.3%	6.8%	13.7%	6.1%
1947-2002	11.8%	6.8%	13.0%	6.3%
1947-2003	12.1%	6.9%	13.3%	6.2%
1947-2004	12.1%	6.9%	13.2%	6.3%
Min	**11.4%**	**2.6%**	**11.5%**	**2.0%**
Max	**13.6%**	**7.0%**	**14.6%**	**6.3%**
Mean	**12.6%**	**5.1%**	**13.1%**	**4.3%**
Stdev.	**0.6%**	**1.6%**	**0.7%**	**1.6%**
+1 Std	**13.1%**	**6.7%**	**13.9%**	**5.9%**
-1 Std dev.	**12.0%**	**3.4%**	**12.4%**	**2.7%**

Source: Ibbotson Associates: Stocks, Bonds, Bills and Inflation: 2005 Yearbook Market Results 1924-2004, Standardandpoors.com; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2004; and TSX.com

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(2004 Backward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-2004	12.1%	6.9%	13.2%	6.3%
1948-2004	12.3%	6.9%	13.4%	6.4%
1949-2004	12.3%	7.1%	13.5%	6.5%
1950-2004	12.2%	7.1%	13.4%	6.5%
1951-2004	11.5%	7.3%	13.1%	6.6%
1952-2004	11.3%	7.5%	12.9%	6.8%
1953-2004	11.5%	7.6%	12.8%	6.9%
1954-2004	11.7%	7.7%	13.0%	7.0%
1955-2004	11.1%	7.6%	12.3%	7.0%
1956-2004	10.8%	7.8%	11.9%	7.1%
1957-2004	10.7%	8.0%	12.0%	7.4%
1958-2004	11.4%	8.1%	12.5%	7.4%
1959-2004	11.0%	8.4%	11.8%	7.7%
1960-2004	11.1%	8.6%	11.8%	7.9%
1961-2004	11.3%	8.7%	12.0%	7.8%
1962-2004	10.8%	8.7%	11.7%	7.9%
1963-2004	11.2%	8.8%	12.2%	8.0%
1964-2004	11.1%	8.9%	11.9%	8.1%
1965-2004	10.8%	8.9%	11.8%	8.2%
1966-2004	10.9%	9.1%	11.8%	8.4%
1967-2004	11.3%	9.3%	12.4%	8.6%
1968-2004	11.2%	9.7%	12.0%	9.0%
1969-2004	10.9%	10.0%	12.1%	9.3%
1970-2004	11.2%	10.3%	12.7%	9.7%
1971-2004	11.6%	9.9%	12.9%	9.6%
1972-2004	11.7%	9.9%	12.9%	9.5%
1973-2004	11.2%	10.2%	12.7%	9.6%
1974-2004	11.6%	10.4%	13.6%	10.0%
1975-2004	12.8%	10.9%	14.9%	10.2%
1976-2004	12.6%	11.1%	14.1%	10.2%
1977-2004	12.7%	10.8%	13.8%	10.0%
1978-2004	12.8%	11.0%	14.6%	10.4%
1979-2004	12.1%	11.4%	14.9%	10.8%
1980-2004	10.8%	12.0%	14.7%	11.3%
Min	**10.7%**	**6.9%**	**11.7%**	**6.3%**
Max	**12.8%**	**12.0%**	**14.9%**	**11.3%**
Mean	**11.5%**	**9.0%**	**12.9%**	**8.4%**
Stdev.	**0.6%**	**1.4%**	**1.0%**	**1.5%**
+1 Std	**12.2%**	**10.5%**	**13.8%**	**9.8%**
-1 Std dev.	**10.9%**	**7.6%**	**11.9%**	**6.9%**

Source: Ibbotson Associates: Stocks, Bonds, Bills and Inflation: 2005 Yearbook Market Results 1924-2004, Standardandpoors.com; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2004; and TSX.com

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS

	Compound Returns						Betas					
	56-97	56-03	64-73	74-83	84-93	94-03	56-97	56-03	64-73	74-83	84-93	94-03
Metals/Minerals	0.08	0.08	0.07	0.11	0.07	0.07	1.23	1.15	1.14	1.22	1.37	0.87
Gold	0.10	0.10	0.16	0.16	0.11	-0.03	0.96	0.85	0.36	1.31	1.24	0.64
Oil and Gas	0.08	0.10	0.15	0.12	0.05	0.15	1.20	1.06	1.25	1.40	0.98	0.52
Paper/Forest	0.07	0.07	0.05	0.12	0.10	0.03	1.07	1.02	1.15	1.00	1.27	0.85
Consumer	0.12	0.11	0.10	0.14	0.11	0.10	0.86	0.83	0.84	0.90	0.89	0.73
Industrial	0.10	0.07	0.08	0.11	0.06	0.01	1.02	1.17	1.11	0.87	1.08	1.69
Real Estate [1/]	0.05	0.05	0.01	0.17	-0.02	0.01	1.18	1.00	1.21	1.28	1.06	0.46
Trans.	0.11	0.10	0.13	0.18	0.03	0.09	1.04	0.94	0.94	1.08	1.22	0.62
Pipes	0.12	0.12	0.05	0.14	0.14	0.13	0.85	0.68	0.80	0.92	0.76	0.02
Utilities	0.11	0.11	0.03	0.18	0.11	0.16	0.48	0.54	0.50	0.47	0.40	0.79
Comm./Media	0.15	0.13	0.19	0.15	0.13	0.07	0.77	0.77	0.96	0.69	0.95	0.80
Mrchnt's	0.11	0.10	0.11	0.12	0.09	0.07	0.86	0.78	0.93	0.84	0.83	0.46
Finance	0.13	0.12	0.12	0.12	0.12	0.18	0.85	0.83	0.95	0.71	0.93	0.77
Mang't.	0.11	0.11	0.13	0.15	0.09	0.14	1.03	0.94	1.26	0.97	1.20	0.68
Intercept							**0.18**	**0.18**	**0.12**	**0.15**	**0.14**	**0.12**
Adjusted R Square							**44%**	**47%**	**1%**	**1%**	**11%**	**9%**
Beta							**-0.082**	**-0.09**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

1/ Data only available starting July 1961

Source: TSX Review

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS

	Compound Returns 1/			Betas		
	88-97	88-04	95-04	88-97	88-04	95-04
Consumer Discretionary	0.102	0.082	0.073	0.904	0.808	0.763
Consumer Staples	0.127	0.150	0.210	0.727	0.361	0.206
Energy	0.084	0.109	0.153	0.765	0.576	0.537
Financials	0.183	0.154	0.176	1.039	0.805	0.704
Health Care	0.155	0.061	0.019	0.807	0.890	0.940
Industrials	0.083	0.055	0.067	1.131	0.985	0.898
Information Technology	0.218	0.082	0.020	1.213	1.895	2.222
Materials	0.034	0.044	0.020	1.257	0.867	0.729
Telecommunications Sector	0.154	0.141	0.148	0.578	0.772	0.868
Utilities	0.115	0.104	0.094	0.624	0.240	0.078
Intercept				**0.14**	**0.13**	**0.15**
Adjusted R Square				**1%**	**15%**	**30%**
Beta				**-0.017**	**-0.03**	**-0.066**

1/ Data only available starting December 1988

Source: TSX Review

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Canadian Utilities	0.45	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03
Emera	N/A	N/A	N/A	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01
Enbridge	0.24	0.26	0.32	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32
Fortis	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01
Terasen Inc	0.41	0.54	0.59	0.54	0.47	0.48	0.36	0.25	0.18	0.12	0.02	-0.02
TransCanada Pipelines	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16
Mean	**0.37**	**0.47**	**0.49**	**0.49**	**0.43**	**0.53**	**0.35**	**0.23**	**0.10**	**0.05**	**-0.13**	**-0.08**
Median	**0.38**	**0.49**	**0.50**	**0.52**	**0.42**	**0.52**	**0.35**	**0.24**	**0.16**	**0.13**	**-0.06**	**-0.01**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13

Adjusted Betas[1/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Canadian Utilities	0.63	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.36	0.35
Emera	N/A	N/A	N/A	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.30	0.34
Enbridge	0.49	0.50	0.54	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12
Fortis	0.56	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.42	0.29	0.34
Terasen Inc	0.60	0.69	0.73	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.34	0.32
TransCanada Pipelines	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22
Mean	**0.58**	**0.64**	**0.66**	**0.66**	**0.62**	**0.68**	**0.57**	**0.48**	**0.40**	**0.37**	**0.24**	**0.28**
Median	**0.58**	**0.66**	**0.66**	**0.68**	**0.61**	**0.68**	**0.56**	**0.49**	**0.44**	**0.41**	**0.29**	**0.33**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.58	0.47	0.44	0.42	NA	NA
S&P/TSX Utilities	0.70	0.75	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24

1/ Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: TSX Review.

BETAS FOR REGULATED CANADIAN UTILITIES
(EXCLUDING NORTEL)

	Raw Betas Five-Year Period Ending					Adjusted Betas Five-Year Period Ending				
	2000	2001	2002	2003	2004	2000	2001	2002	2003	2004
Canadian Utilities	0.57	0.46	0.37	0.24	0.20	0.71	0.64	0.58	0.49	0.46
Emera	0.43	0.35	0.29	0.02	0.07	0.62	0.56	0.52	0.34	0.38
Enbridge	0.29	0.13	0.05	-0.15	0.01	0.52	0.42	0.36	0.23	0.34
Fortis	0.36	0.28	0.28	0.05	0.07	0.57	0.52	0.52	0.36	0.38
Terasen Inc	0.41	0.35	0.28	0.22	0.22	0.60	0.56	0.52	0.48	0.48
TransCanada Pipelines	0.40	0.15	0.16	-0.19	0.03	0.60	0.43	0.44	0.20	0.35
Mean	**0.41**	**0.29**	**0.24**	**0.03**	**0.10**	**0.60**	**0.52**	**0.49**	**0.35**	**0.40**
Median	**0.41**	**0.32**	**0.28**	**0.04**	**0.07**	**0.60**	**0.54**	**0.52**	**0.35**	**0.38**
TSE Gas/Electric Index	0.40	0.37	0.33	NA	NA	0.60	0.58	0.55	NA	NA
S&P/TSX Utilities	0.35	0.18	0.16	-0.05	0.11	0.56	0.45	0.44	0.30	0.40

Source: TSX Review

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Consumer Discretionary	0.91	0.81	0.82	0.82	0.80	0.73	0.69	0.68	0.73	0.74	0.80
Consumer Staples	0.75	0.68	0.65	0.62	0.60	0.44	0.23	0.10	0.08	-0.08	-0.07
Energy	0.68	0.93	0.92	0.97	0.85	0.90	0.66	0.49	0.43	0.26	0.17
Financials	1.14	0.93	1.02	0.94	1.12	1.00	0.78	0.66	0.66	0.38	0.39
Health Care	0.84	0.35	0.39	0.60	1.01	1.00	1.09	0.98	0.99	0.85	0.82
Industrials	1.15	1.20	1.10	0.97	0.93	0.78	0.72	0.82	0.86	0.91	1.04
Information Technology	1.12	1.26	1.36	1.57	1.41	1.55	1.78	2.13	2.28	2.74	2.87
Materials	1.26	1.39	1.27	1.32	1.12	1.04	0.74	0.60	0.57	0.43	0.41
Telecommunication Services	0.61	0.56	0.64	0.64	0.92	1.11	0.92	0.94	0.93	0.83	0.58
Utilities	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13

Source: TSX Review

RECENT SUB-PERIOD BETAS FOR REGULATED CANADIAN UTILITIES

Including Nortel in the Market Index

COMPANY	Raw 1/2000 to 6/2002	Raw 1/2002 to 12/2004	Raw 4/2002 to 12/2004	Raw 7/2002 to 12/2004	Adjusted 1/2000 to 6/2002	Adjusted 1/2002 to 12/2004	Adjusted 4/2002 to 12/2004	Adjusted 7/2002 to 12/2004
Canadian Utilities	-0.09	0.42	0.41	0.52	0.27	0.61	0.61	0.68
Emera	-0.04	0.12	0.11	0.16	0.31	0.41	0.40	0.43
Enbridge	-0.52	0.29	0.30	0.35	-0.02	0.52	0.53	0.56
Fortis	-0.12	0.36	0.37	0.44	0.25	0.57	0.58	0.62
Terasen Inc	-0.07	0.16	0.14	0.18	0.28	0.44	0.42	0.45
TransCanada Pipelines	-0.34	0.33	0.38	0.47	0.10	0.55	0.58	0.65
Mean	**-0.20**	**0.28**	**0.29**	**0.35**	**0.20**	**0.52**	**0.52**	**0.57**
Median	**-0.11**	**0.31**	**0.34**	**0.39**	**0.26**	**0.54**	**0.56**	**0.59**
S&P/TSX Utilities	-0.30	0.34	0.36	0.44	0.13	0.56	0.57	0.62

Excluding Nortel from the Market Index

COMPANY	Raw 1/2000 to 6/2002	Raw 1/2002 to 12/2004	Raw 4/2002 to 12/2004	Raw 7/2002 to 12/2004	Adjusted 1/2000 to 6/2002	Adjusted 1/2002 to 12/2004	Adjusted 4/2002 to 12/2004	Adjusted 7/2002 to 12/2004
Canadian Utilities	0.06	0.42	0.38	0.46	0.37	0.61	0.59	0.64
Emera	0.00	0.15	0.14	0.19	0.33	0.43	0.43	0.46
Enbridge	-0.33	0.50	0.52	0.58	0.11	0.67	0.68	0.72
Fortis	-0.11	0.32	0.31	0.37	0.26	0.54	0.54	0.58
Terasen Inc	0.13	0.35	0.32	0.37	0.42	0.56	0.54	0.58
TransCanada Pipelines	-0.29	0.45	0.49	0.57	0.14	0.63	0.66	0.71
Mean	**-0.09**	**0.36**	**0.36**	**0.42**	**0.27**	**0.57**	**0.57**	**0.61**
Median	**-0.05**	**0.38**	**0.35**	**0.42**	**0.29**	**0.59**	**0.56**	**0.61**
S&P/TSX Utilities	-0.14	0.46	0.48	0.55	0.23	0.64	0.65	0.70

Source: TSX Review

FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX

Index	1997	1998	1999	2000	2001	2002	2003	2004
	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
S&P / TSX	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**
10 Sector Indices								
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**

Source: TSX Review

CANADIAN AND U.S. UTILITY
HISTORIC EQUITY RISK PREMIUMS

CANADIAN UTILITIES INDEX
(1956-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.2	7.8	4.4
Geometric	11.1	7.3	3.8

S&P / MOODY'S ELECTRIC INDEX
(1947-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	11.3	6.3	5.0
Geometric	10.1	5.8	4.3

S&P / MOODY'S GAS DISTRIBUTION INDEX
(1947-2004)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.3	6.3	6.0
Geometric	11.2	5.8	5.4

Note: The Canadian data reflect the S&P/TSX Utilities Index from 1988-2004; and the TSE Gas/Electric Index from 1956-1987. The U.S. data reflect S&P's utility indices from 1947 to 1984, when S&P eliminated its gas distribution index. The 1984-2001 U.S. data are for Moody's Gas and Electric indices. The Moody's Gas and Electric Indices were terminated in July 2002. The 2002-2004 returns for the U.S. gas and electric utilities were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's indices as of the end of 2001.

Sources: TSX Review; Bank of Canada Review; Standard & Poor's Analysts' Handbook; Ibbotson Associates, Stocks, Bonds, Bills and Inflation 2005 Yearbook Market Results 1924-2004; Mergent Corporate News Reports.

Tab 2
Schedule 17

INDIVIDUAL COMPANY RISK DATA FOR
SELECTED LOCAL NATURAL GAS DISTRIBUTION COMPANIES

Company	Value Line							S & P		Average Market / Book Ratio 1993-2004	Repriced Equity / Book 2004
	Safety Rank	Earnings Predictability	Financial Strength	Beta	Forecast Common Equity Ratio 2008-2010	Forecast Return On Average Common Equity 2008-2010	Dividend Payout Forecast 2008-2010	Business Profile	Debt Rating		
AGL RESOURCES INC	2	65	B++	0.85	54.0	11.9	49%	4	A-	176	135
NEW JERSEY RESOURCES	2	100	B++	0.75	69.5	11.8	47%	2	A+	212	144
NICOR INC	3	80	A	1.10	63.0	13.5	79%	3	AA	227	260
NORTHWEST NATURAL GAS	3	80	A	0.70	63.0	10.8	59%	1	A+	154	157
PEOPLES ENERGY CORP	1	80	A	0.80	53.5	11.0	73%	5	A-	166	272
PIEDMONT NATURAL GAS	2	80	B++	0.75	62.5	11.9	69%	2	A	200	133
WGL HOLDINGS INC	1	60	A	0.75	63.5	13.1	54%	3	AA-	174	163
MEAN	**2**	**78**	**A**	**0.81**	**61.3**	**12.0**	**61%**	**3**	**A+**	**187**	**180**
MEDIAN	**2**	**80**	**A**	**0.75**	**63.0**	**11.9**	**59%**	**3**	**A+**	**176**	**157**

1/ For subsidiary, New Jersey Natural Gas

Source: Value Line (June 17, 2005)
Standard & Poor's "U.S. Utility and Power Ranking List" (June 17, 2005)

Tab 2
Schedule18

DCF-BASED EQUITY RISK PREMIUM TEST FOR SELECTED U.S. LOCAL NATURAL GAS DISTRIBUTION COMPANIES
(Annual Averages of Monthly Data)

	Dividend Yields [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	30-Year Treasury Yield	Risk Premium
1993	5.2	5.7	10.9	6.6	4.3
1994	6.0	4.9	10.9	7.4	3.5
1995	5.9	4.5	10.4	6.9	3.5
1996	5.3	4.9	10.2	6.7	3.5
1997	4.9	4.8	9.7	6.6	3.1
1998	4.6	5.4	10.1	5.5	4.5
1999	5.0	5.3	10.3	5.9	4.4
2000	5.3	5.4	10.7	5.9	4.8
2001	4.8	5.7	10.5	5.5	5.0
2002	4.9	5.6	10.5	5.4	5.1
2003	4.8	5.2	10.0	5.0	5.0
2004	4.4	4.4	8.8	5.1	3.7
Means for 30-year Treasury yields:					
5.5% and below			**9.8**	**5.1**	**4.7**
5.6 - 6.0%			**10.3**	**5.8**	**4.5**
6.1 - 6.5%			**10.2**	**6.2**	**3.9**
Over 6.5%			**10.6**	**7.1**	**3.5**
All periods			**10.2**	**6.0**	**4.2**

[1/] Dividend Yield is adjusted for half of I/B/E/S growth

Source: Standard and Poor's Research Insight, I/B/E/S and the U.S. Federal Reserve

Tab 2
Schedule 19

INDIVIDUAL COMPANY RISK DATA FOR SELECTED LOW RISK
ELECTRIC AND LOCAL NATURAL GAS DISTRIBUTION UTILITIES

	Value Line							S & P			
Company	Safety Rank	Earnings Predictability	Financial Strength	Beta	Forecast Common Equity Ratio 2008-2010	Forecast Return On Average Common Equity 2008-2010	Dividend Payout Forecast 2008-2010	Business Profile	Debt Rating	Average Market/ Book Ratio 1993-2004	Repriced Equity / Book 2004
AGL Resources	2	65	B++	0.85	54.0	11.9	49%	4	A-	176	135
Consolidated Edison	1	90	A++	0.60	51.5	9.3	79%	2	A	148	155
KeySpan Corp.	2	20	B++	0.80	50.0	11.0	62%	4	A	138	155
New Jersey Resources	2	100	B++	0.75	69.5	11.8	47%	2	A+	212	144
NICOR Inc.	3	80	A	1.10	63.0	13.5	79%	3	AA	227	260
Northwest Nat. Gas	3	80	A	0.70	63.0	10.8	59%	1	A+	154	157
NSTAR	1	95	A	0.70	52.5	12.0	68%	1	A	165	156
Peoples Energy	1	80	A	0.80	53.5	11.0	73%	5	A-	166	272
Piedmont Natural Gas	2	80	B++	0.75	62.5	11.9	69%	2	A	200	133
SCANA Corp.	2	85	A	0.75	53.5	11.3	58%	4	A-	164	142
Southern Co.	1	90	A	0.65	47.5	13.9	68%	4	A	200	159
Vectren Corp.	2	70	A+	0.75	55.5	11.5	69%	4	A-	194	120
WGL Holdings Inc.	1	60	A	0.75	63.5	13.1	54%	3	AA-	174	163
WPS Resources	2	85	B++	0.75	55.5	11.8	56%	5	A	164	133
MEAN	**2**	**77**	**A**	**0.76**	**56.8**	**11.8**	64%	3	A	177	163
MEDIAN	**2**	**80**	**A**	**0.75**	**54.8**	**11.8**	65%	4	A	170	155

Source: Value Line (April 1, 2005, June 3, 2005 and June 17, 2005)
Standard & Poor's "U.S. Power and Utility Ranking" (June 17, 2005)

DCF COSTS OF EQUITY FOR SELECTED LOW RISK ELECTRIC AND LOCAL NATURAL GAS DISTRIBUTION UTILITIES (BASED ON I/B/E/S MEDIAN LONG-TERM GROWTH FORECASTS)

Company	Dividend Yield	Adjusted Dividend Yield [1/]	Long-Term I/B/E/S Growth Forecasts Median	DCF Cost of Equity
AGL Resources	3.58	3.72	4.0	7.7
Consolidated Edison	5.30	5.46	3.0	8.5
KeySpan Corp.	4.69	4.85	3.5	8.3
New Jersey Resources	3.09	3.26	5.5	8.8
NICOR Inc.	4.99	5.09	2.0	7.1
Northwest Nat. Gas	3.65	3.86	5.8	9.6
NSTAR	4.19	4.40	5.0	9.4
Peoples Energy	5.23	5.44	4.0	9.4
Piedmont Natural Gas	3.97	4.16	5.0	9.2
SCANA Corp.	4.04	4.22	4.5	8.7
Southern Co.	4.58	4.81	5.0	9.8
Vectren Corp.	4.42	4.61	4.5	9.1
WGL Holdings Inc.	4.32	4.49	4.0	8.5
WPS Resources	4.19	4.38	4.5	8.9
Mean	**4.30**	**4.48**	**4.3**	**8.8**
Median	**4.25**	**4.45**	**4.5**	**8.8**

1/ Adjusted dividend yield plus growth ([DY*(1+(Growth))] + Growth);
Prices based on average monthly high/low price for three months ended May 2005.

Source: Standard & Poor's Research Insight; I/B/E/S (May 2005)

DCF COSTS OF EQUITY FOR SELECTED LOW RISK ELECTRIC AND LOCAL NATURAL GAS DISTRIBUTION UTILITIES (BASED ON VALUE LINE LONG-TERM EPS GROWTH FORECASTS)

Company	Dividend Yield	Adjusted Dividend Yield 1/	Value Line Long-Term EPS Growth Forecasts	DCF Cost of Equity
AGL Resources	3.58	3.76	5.0	8.8
Consolidated Edison	5.30	5.38	1.5	6.9
KeySpan Corp.	4.69	4.73	1.0	5.7
New Jersey Resources	3.09	3.34	8.0	11.3
NICOR Inc.	4.99	5.04	1.0	6.0
Northwest Nat. Gas	3.65	3.92	7.5	11.4
NSTAR	4.19	4.30	2.5	6.8
Peoples Energy	5.23	5.28	1.0	6.3
Piedmont Natural Gas	3.97	4.26	7.5	11.8
SCANA Corp.	4.04	4.22	4.5	8.7
Southern Co.	4.58	4.77	4.0	8.8
Vectren Corp.	4.42	4.61	4.5	9.1
WGL Holdings Inc.	4.32	4.60	6.5	11.1
WPS Resources	4.19	4.46	6.5	11.0
Mean	**4.30**	**4.48**	**4.4**	**8.8**
Median	**4.25**	**4.53**	**4.5**	**8.8**

1/ Adjusted dividend yield plus growth ([DY*(1+(Growth))] + Growth);
Prices based on average monthly high/low price in three months ending May 2005.

Source: Standard & Poor's Research Insight; Value Line (April and June 2005)

DCF COSTS OF EQUITY FOR SELECTED LOW RISK ELECTRIC AND LOCAL NATURAL GAS DISTRIBUTION UTILITIES (TWO-STAGE MODEL)

Company	Annualized Last Paid Dividend (1)	Average High/Low March - May 2005 Price (2)	Stage 1 I/B/E/S EPS Forecasts (3)	Stage 2 GDP Growth 1/ (4)	DCF Cost of Equity 2/ (5)
AGL Resources	1.24	34.65	4.0	5.5	8.9
Consolidated Edison	2.28	43.04	3.0	5.5	10.5
KeySpan Corp.	1.82	38.84	3.5	5.5	10.0
New Jersey Resources	1.36	43.97	5.5	5.5	8.6
NICOR Inc.	1.86	37.26	2.0	5.5	9.9
Northwest Nat. Gas	1.30	35.65	5.8	5.5	9.3
NSTAR	2.32	55.34	5.0	5.5	9.7
Peoples Energy	2.18	41.67	4.0	5.5	10.6
Piedmont Natural Gas	0.92	23.20	5.0	5.5	9.5
SCANA Corp.	1.56	38.59	4.5	5.5	9.5
Southern Co.	1.49	32.56	5.0	5.5	10.2
Vectren Corp.	1.18	26.73	4.5	5.5	9.9
WGL Holdings Inc.	1.33	30.86	4.0	5.5	9.7
WPS Resources	2.22	53.00	4.5	5.5	9.6
Mean	**1.65**	**38.24**	**4.3**	**5.5**	**9.7**
Median	**1.53**	**37.92**	**4.5**	**5.5**	**9.7**

1/ Consensus forecast of nominal rate of GDP growth, 2007-16

2/ Internal Rate of Return: I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter

Source: Standard & Poor's Research Insight; Blue Chip Financial Forecasts (June 1, 2005); I/B/E/S (May 2005)

RISK MEASURES FOR 17 LOW RISK CANADIAN INDUSTRIALS

	Debt Ratings			Beta				Equity Ratio
				1999-2003		2000-2004		Total Capital
Company Name	S&P	DBRS	CBS Stock Rating	Raw	Adjusted	Raw	Adjusted	2003
ALGOMA CENTRAL CORP			Average	-0.11	0.26	0.06	0.37	85.6%
CANADA BREAD CO LTD			Conservative	0.11	0.40	0.34	0.56	74.0%
CANADIAN TIRE CORP -CL A	BBB+	A(low)	Very Conservative	0.24	0.49	0.30	0.53	64.3%
EMPIRE CO LTD -CL A	BBB-	BBB	Very Conservative	0.33	0.55	0.28	0.52	57.9%
FINNING INTERNATIONAL INC	BBB+	BBB(high)	Conservative	0.14	0.42	0.11	0.41	46.8%
LEON'S FURNITURE LTD			Average	0.20	0.46	0.24	0.49	100.0%
LINAMAR CORP			Average	0.29	0.52	0.43	0.62	65.7%
LOBLAW COMPANIES LTD	A	A(high)	Very Conservative	-0.13	0.24	-0.02	0.32	50.2%
MAGNA INTERNATIONAL -CL A	A	A	Conservative	0.33	0.55	0.50	0.66	83.5%
MAPLE LEAF FOODS INC			Very Conservative	0.19	0.46	0.37	0.58	50.3%
METRO INC -CL A	A		Very Conservative	0.26	0.51	0.20	0.46	89.1%
QUEBECOR WORLD INC -SUB VTG	BBB-	BBB(low)	Very Conservative	0.22	0.48	0.35	0.56	45.3%
REITMANS (CANADA) -CL A			Average	-0.13	0.24	0.14	0.42	74.5%
THOMSON CORP	A-	A(low)	Very Conservative	0.52	0.68	0.53	0.69	67.6%
TORSTAR CORP -CL B		BBB(high)	Very Conservative	0.28	0.52	0.34	0.56	65.6%
TRANSCONTINENTAL INC -CL A	BBB	BBB(high)	Very Conservative	0.30	0.53	0.35	0.57	68.4%
WESTON (GEORGE) LTD	A-	A(low)	Very Conservative	-0.10	0.27	-0.08	0.28	34.6%
MEAN	**BBB+**	**BBB(high)**	**Conservative**	**0.17**	**0.45**	**0.26**	**0.50**	**66.1%**
MEDIAN	**BBB+**	**BBB(high)**	**Very Conservative**	**0.22**	**0.48**	**0.30**	**0.53**	**65.7%**

Source: Standard & Poor's Ratings Direct; DBRS; Canadian Business Service; Standard & Poor's Research Insight.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
17 LOW RISK CANADIAN INDUSTRIALS

Company Name	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Average 1993-2004	Average 1993-1995	Average 1996-2004
ALGOMA CENTRAL CORP	11.0	19.0	13.3	12.3	52.7	8.5	3.8	1.1	14.8	9.3	4.7	9.2	13.3	14.4	12.9
CANADA BREAD CO LTD	15.6	14.5	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	10.6	14.2	9.4
CANADIAN TIRE CORP -CL A	6.9	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	10.3	5.8	11.8
EMPIRE CO LTD -CL A	12.3	9.4	3.9	11.9	17.9	21.7	13.3	69.1	16.4	11.4	11.6	10.7	17.5	8.5	20.4
FINNING INTERNATIONAL INC	6.5	14.9	16.3	16.0	16.2	0.5	8.7	10.5	14.1	15.5	14.0	10.1	11.9	12.6	11.7
LEON'S FURNITURE LTD	16.4	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	16.8	15.3	17.3
LINAMAR CORP	20.5	27.7	22.3	29.0	36.9	21.9	14.7	15.7	7.8	9.7	6.5	14.0	18.9	23.5	17.4
LOBLAW COMPANIES LTD	9.6	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	15.1	11.8	16.2
MAGNA INTERNATIONAL -CL A	19.6	21.7	21.8	15.8	21.6	12.3	12.0	15.9	14.7	11.8	9.5	13.3	15.8	21.0	14.1
MAPLE LEAF FOODS INC	7.3	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	8.1	2.7	9.9
METRO INC -CL A	13.0	16.2	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	21.4	17.3	22.7
QUEBECOR WORLD INC -SUB VTG	13.7	13.3	11.8	11.4	11.1	12.0	3.9	13.3	0.0	11.7	-2.8	4.9	8.7	12.9	7.3
REITMANS (CANADA) -CL A	11.1	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	12.2	8.8	13.3
THOMSON CORP	10.0	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	14.3	15.6	13.8
TORSTAR CORP -CL B	-1.7	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	9.9	4.3	11.8
TRANSCONTINENTAL INC -CL A	9.3	8.1	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	10.7	8.9	11.3
WESTON (GEORGE) LTD	4.5	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	15.9	8.7	18.3
Mean	10.9	13.0	12.5	13.4	19.8	13.3	12.9	16.1	11.0	14.3	12.3	13.7	13.6	12.1	14.1
Median	11.0	13.3	12.9	13.4	15.1	12.3	12.8	13.7	12.6	12.2	12.8	13.6	13.3	12.6	13.3
													13.0	13.2	13.1

RISK MEASURES FOR 188 LOW RISK US INDUSTRIALS

			Beta				
			1999-2003		2000-2004		
Company Name	S&P Debt Rating	Value Line Safety Rank	Raw	Adjusted	Raw	Adjusted	Equity Ratio Total Capital 2003
3M CO	AA	1	0.58	0.72	0.55	0.70	72.4%
ABM INDUSTRIES INC		2	0.48	0.65	0.44	0.62	100.0%
ACETO CORP		3	0.60	0.73	0.99	0.99	96.3%
ALAMO GROUP INC		2	0.21	0.47	0.36	0.57	90.0%
ALBERTO-CULVER CO	BBB+	1	0.28	0.52	0.25	0.50	76.8%
ALBERTSONS INC	BBB	3	0.26	0.50	0.38	0.59	50.3%
ALEXANDER & BALDWIN INC	A-	3	0.47	0.64	0.66	0.77	70.2%
ALICO INC		3	0.15	0.43	0.30	0.53	68.7%
AMERON INTERNATIONAL CORP		3	0.45	0.63	0.62	0.75	73.1%
ANDERSONS INC		3	-0.16	0.22	-0.10	0.27	46.1%
APOGEE ENTERPRISES INC		3	0.43	0.62	0.34	0.56	80.7%
APPLEBEES INTL INC		3	0.18	0.45	0.36	0.57	95.7%
APPLIED INDUSTRIAL TECH INC		3	0.05	0.37	0.19	0.46	79.7%
ARCHER-DANIELS-MIDLAND CO	A+	3	0.33	0.55	0.38	0.59	57.7%
ARCTIC CAT INC		3	0.66	0.77	0.87	0.91	100.0%
AVERY DENNISON CORP	A-	2	0.71	0.81	0.50	0.67	52.8%
BADGER METER INC		3	0.27	0.51	0.34	0.56	62.1%
BALDOR ELECTRIC CO		2	0.33	0.55	0.43	0.62	71.3%
BANDAG INC		3	0.81	0.87	1.01	1.01	95.4%
BANTA CORP		2	0.15	0.43	0.36	0.57	82.1%
BARNES GROUP INC		3	0.23	0.49	0.33	0.55	57.2%
BLAIR CORP		3	0.40	0.60	0.31	0.54	94.6%
BLOCK H & R INC	BBB+	3	0.25	0.50	0.25	0.50	69.8%
BOB EVANS FARMS		2	0.09	0.39	0.36	0.57	90.9%
BOEING CO	A	3	0.71	0.81	0.72	0.81	36.0%
BRADY CORP		3	1.00	1.00	0.79	0.86	99.6%
BRIDGFORD FOODS CORP		3	0.04	0.36	0.02	0.34	100.0%
BRIGGS & STRATTON	BBB-	3	0.91	0.94	1.07	1.05	50.4%
BRINKS CO	BBB	3	0.53	0.69	0.74	0.83	64.4%
BROWN-FORMAN -CL B	A	1	0.33	0.55	0.28	0.52	61.5%
BRUNSWICK CORP	BBB+	3	0.85	0.90	0.89	0.93	68.5%
BURLINGTON NORTHERN SANTA FE	BBB+	3	0.55	0.70	0.60	0.73	56.0%
CASEYS GENERAL STORES INC		3	0.49	0.66	0.47	0.64	71.8%
CATO CORP -CL A		3	0.54	0.69	0.80	0.87	87.6%
CBRL GROUP INC	BBB-	3	0.25	0.50	-0.02	0.32	81.0%
CHURCHILL DOWNS INC		3	0.38	0.59	0.34	0.56	66.8%
CLARCOR INC		2	0.43	0.61	0.40	0.60	95.5%
CLOROX CO/DE	A-	2	0.38	0.58	0.21	0.47	53.2%
CONAGRA FOODS INC	BBB+	1	0.28	0.51	0.70	0.80	45.9%
COURIER CORP		2	0.53	0.69	0.62	0.74	99.4%
CPI CORP		3	0.01	0.34	0.18	0.45	60.3%
CSX CORP	BBB	3	0.61	0.74	0.75	0.83	46.9%
CUBIC CORP		3	0.16	0.44	0.09	0.39	82.3%
CURTISS-WRIGHT CORP		2	0.02	0.35	0.05	0.36	68.0%
CVS CORP	A-	3	0.51	0.67	0.53	0.69	83.7%
DANAHER CORP	A+	2	0.86	0.91	0.89	0.93	73.7%
DEB SHOPS INC		3	0.38	0.58	0.30	0.53	100.0%
DELTA & PINE LAND CO		2	0.29	0.52	0.30	0.53	99.2%
DONALDSON CO INC		2	0.50	0.66	0.57	0.71	78.9%
DONNELLEY (R R) & SONS CO	A-	2	0.54	0.69	0.71	0.81	51.4%
EATON CORP	A-	1	0.65	0.77	0.75	0.83	61.5%
ELKCORP		3	0.58	0.72	0.43	0.62	56.3%
EMERSON ELECTRIC CO	A	1	0.82	0.88	0.96	0.97	61.0%
ENGINEERED SUPPORT SYSTEMS		3	-0.13	0.24	0.12	0.41	72.9%
ENNIS INC		3	0.10	0.40	0.27	0.51	88.7%
EW SCRIPPS -CL A	A	2	0.49	0.66	0.55	0.70	78.2%
EXPEDITORS INTL WASH INC		3	0.68	0.79	0.61	0.74	100.0%
FAMILY DOLLAR STORES		3	0.69	0.79	0.50	0.66	100.0%
FARMER BROS CO		2	0.22	0.48	0.06	0.37	100.0%
FASTENAL CO		3	0.49	0.66	0.54	0.69	100.0%
FEDERAL SCREW WORKS		2	-0.08	0.28	-0.09	0.27	90.7%
FEDERAL SIGNAL CORP		3	0.86	0.90	1.05	1.03	47.5%
FLEXSTEEL INDS		3	0.27	0.51	0.31	0.54	100.0%
FLUOR CORP	A-	3	0.40	0.60	0.51	0.67	80.3%
FRANKLIN ELECTRIC CO INC		2	0.24	0.49	0.30	0.53	92.2%
FREDS INC		3	0.62	0.75	0.72	0.81	97.3%

RISK MEASURES FOR 188 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety Rank	Beta 1999-2003 Raw	Beta 1999-2003 Adjusted	Beta 2000-2004 Raw	Beta 2000-2004 Adjusted	Equity Ratio Total Capital 2003
FRISCH'S RESTAURANTS INC		3	-0.10	0.26	0.60	0.73	63.8%
G&K SERVICES INC -CL A		3	0.52	0.68	0.40	0.60	60.2%
GANNETT CO	A	1	0.68	0.79	0.60	0.73	68.7%
GATX CORP	BBB-	3	0.94	0.96	1.04	1.03	18.8%
GENERAL DYNAMICS CORP	A	1	0.51	0.67	0.57	0.71	59.4%
GENUINE PARTS CO		1	0.41	0.60	0.50	0.67	77.3%
GORMAN-RUPP CO		3	0.60	0.73	0.67	0.78	100.0%
GRAINGER (W W) INC	AA+	2	0.65	0.76	0.80	0.87	92.5%
GRANITE CONSTRUCTION INC		3	0.24	0.49	0.32	0.55	78.9%
HANCOCK FABRICS INC		3	-0.30	0.13	-0.08	0.28	92.9%
HARLAND (JOHN H.) CO		3	-0.06	0.29	-0.05	0.29	67.7%
HARSCO CORP	A-	3	0.86	0.91	0.96	0.97	55.9%
HARTE HANKS INC		1	0.18	0.45	0.24	0.49	99.1%
HAVERTY FURNITURE		3	0.68	0.79	0.83	0.88	76.2%
HEICO CORP		3	0.37	0.58	0.47	0.65	87.4%
HILTON HOTELS CORP	BBB-	3	0.78	0.85	0.96	0.97	35.1%
HNI CORP		2	0.93	0.95	0.89	0.93	95.8%
HORMEL FOODS CORP	A	1	0.15	0.43	0.14	0.43	75.4%
HUBBELL INC -CL B	A+	2	0.86	0.90	0.87	0.91	73.5%
IDEX CORP	BBB	3	0.73	0.82	0.77	0.85	77.0%
ILLINOIS TOOL WORKS	AA	2	0.83	0.89	0.86	0.91	89.0%
INTL SPEEDWAY CORP -CL A	BBB-	3	0.28	0.51	0.22	0.48	70.2%
JOHNSON CONTROLS INC	A	2	0.83	0.88	0.70	0.80	63.3%
KELLWOOD CO	BBB-	3	0.54	0.69	0.59	0.73	70.1%
KELLY SERVICES INC -CL A		3	0.30	0.53	0.46	0.63	94.0%
KIMBALL INTERNATIONAL -CL B		3	0.25	0.50	0.32	0.54	99.5%
KIMBERLY-CLARK CORP	AA-	1	0.25	0.50	0.14	0.42	65.3%
KNIGHT-RIDDER INC	A	1	0.66	0.77	0.63	0.75	49.8%
LANCASTER COLONY CORP		1	0.30	0.53	0.11	0.41	100.0%
LANCE INC		3	0.15	0.43	0.33	0.55	80.7%
LAWSON PRODUCTS		2	0.44	0.62	0.51	0.67	98.3%
LA-Z-BOY INC		3	0.64	0.76	0.83	0.88	70.0%
LEE ENTERPRISES INC		1	0.72	0.82	0.76	0.84	72.4%
LEGGETT & PLATT INC	A+	2	0.97	0.98	1.03	1.02	64.3%
LENNAR CORP	BBB-	3	0.73	0.82	0.55	0.70	58.7%
LIBERTY CORP		2	0.52	0.68	0.63	0.75	100.0%
LIFETIME HOAN CORP		3	0.82	0.88	1.04	1.03	83.1%
LINCOLN ELECTRIC HLDGS INC		2	0.56	0.71	0.66	0.77	73.4%
LINDSAY MANUFACTURING CO		3	0.28	0.52	0.43	0.62	100.0%
LONGS DRUG STORES CORP		3	0.27	0.51	0.38	0.58	77.6%
LSI INDS INC		3	0.42	0.61	0.32	0.55	89.9%
MARCUS CORP		3	0.76	0.84	0.90	0.93	62.2%
MASCO CORP	BBB+	3	0.70	0.80	0.76	0.84	56.6%
MAY DEPARTMENT STORES CO	BBB	3	0.72	0.81	0.87	0.91	50.1%
MCCLATCHY CO -CL A	BBB+	1	0.17	0.44	0.19	0.46	77.8%
MCCORMICK & COMPANY INC	A	2	0.00	0.33	0.05	0.37	54.9%
MCDONALD'S CORP	A	1	0.76	0.84	0.90	0.93	55.2%
MCGRATH RENTCORP		3	0.63	0.75	0.83	0.89	75.3%
MCGRAW-HILL COMPANIES		1	0.56	0.70	0.45	0.63	99.0%
MDC HOLDINGS INC	BBB-	3	0.85	0.90	0.85	0.90	63.7%
MEREDITH CORP		1	0.50	0.67	0.35	0.57	57.2%
MET-PRO CORP		2	0.26	0.51	0.32	0.54	89.6%
MINE SAFETY APPLIANCES CO		3	-0.25	0.16	-0.22	0.18	81.5%
MODINE MANUFACTURING CO		3	0.87	0.91	0.93	0.96	87.0%
MOVADO GROUP INC		3	0.43	0.62	0.43	0.62	88.7%
NATURES SUNSHINE PRODS INC		3	-0.05	0.30	0.29	0.52	93.9%
NEW YORK TIMES CO -CL A	A+	1	0.72	0.81	0.57	0.71	59.3%
NIKE INC -CL B	A	2	0.71	0.81	0.90	0.93	85.1%
NORDSON CORP		3	0.86	0.91	0.91	0.94	54.8%
NORFOLK SOUTHERN CORP	BBB	3	0.49	0.66	0.61	0.74	47.0%
NORTHROP GRUMMAN CORP	BBB	3	-0.32	0.12	-0.12	0.25	71.7%
OSHKOSH TRUCK CORP		3	0.78	0.85	0.75	0.83	87.8%
PALL CORP	A-	2	0.86	0.90	1.00	1.00	62.8%
PARKER-HANNIFIN CORP	A	3	0.96	0.98	1.06	1.04	64.4%
PENTAIR INC	BBB	3	0.90	0.93	0.98	0.99	61.0%
PEPSIAMERICAS INC	A	3	0.10	0.40	0.30	0.53	54.8%
PIER 1 IMPORTS INC/DE	BBB-	3	0.28	0.52	0.67	0.78	97.3%
PULITZER INC		2	0.31	0.54	0.52	0.68	73.6%
PULTE HOMES INC	BBB-	3	0.94	0.96	1.04	1.02	56.7%

RISK MEASURES FOR 188 LOW RISK US INDUSTRIALS

			Beta				
			1999-2003		2000-2004		
Company Name	S&P Debt Rating	Value Line Safety Rank	Raw	Adjusted	Raw	Adjusted	Equity Ratio Total Capital 2003
QUIXOTE CORP		3	0.41	0.61	0.49	0.66	63.3%
RAVEN INDUSTRIES INC		3	0.24	0.49	0.34	0.56	99.8%
RAYTHEON CO	BBB-	3	0.23	0.48	0.36	0.57	55.3%
REGIS CORP/MN		3	0.58	0.72	0.39	0.59	65.1%
ROBBINS & MYERS INC		3	0.72	0.81	0.71	0.81	59.7%
ROCKWELL AUTOMATION	A	2	0.94	0.96	0.93	0.95	67.2%
ROLLINS INC		3	0.11	0.41	0.19	0.45	100.0%
RUBY TUESDAY INC		3	0.18	0.45	0.85	0.90	75.4%
RUSS BERRIE & CO INC		3	0.27	0.51	0.25	0.50	100.0%
RYDER SYSTEM INC	BBB+	3	0.80	0.87	0.80	0.87	42.5%
RYLAND GROUP INC	BBB-	3	0.87	0.91	1.05	1.03	59.3%
SCHAWK INC -CL A		1	0.15	0.43	0.37	0.58	79.7%
SKYLINE CORP		3	0.62	0.74	0.85	0.90	100.0%
SMITH (A O) CORP		3	0.11	0.41	0.19	0.46	67.7%
SMUCKER (JM) CO		2	0.12	0.41	0.08	0.38	90.0%
SOUTHWEST AIRLINES	A	3	0.86	0.90	0.87	0.91	76.7%
STANDEX INTERNATIONAL CORP		2	0.51	0.67	0.37	0.58	59.6%
STANLEY WORKS	A	3	0.89	0.93	0.91	0.94	55.4%
STRIDE RITE CORP		3	0.92	0.95	0.94	0.96	100.0%
STURM RUGER & CO INC		3	-0.01	0.32	0.05	0.36	100.0%
SUPERIOR INDUSTRIES INTL		3	0.64	0.76	0.66	0.77	100.0%
SUPERIOR UNIFORM GROUP INC		2	-0.01	0.33	0.10	0.40	91.9%
SUPERVALU INC	BBB	3	0.47	0.64	0.59	0.72	53.3%
SYSCO CORP	AA-	1	0.54	0.69	0.39	0.59	61.6%
TECUMSEH PRODUCTS CO -CL A		2	0.36	0.57	0.49	0.66	70.7%
TELEFLEX INC		2	0.57	0.71	0.83	0.89	70.0%
TENNANT CO		2	0.27	0.51	0.42	0.61	95.8%
THOMAS INDUSTRIES INC		2	0.79	0.86	0.81	0.87	76.8%
THOR INDUSTRIES INC		3	0.79	0.86	0.74	0.83	100.0%
TOOTSIE ROLL INDUSTRIES INC		1	0.52	0.68	0.62	0.74	98.6%
TORO CO	BBB-	2	0.54	0.69	0.32	0.54	70.7%
TREDEGAR CORP		3	0.31	0.54	0.24	0.49	76.2%
TRIBUNE CO	A	1	0.66	0.77	0.51	0.67	72.4%
TYSON FOODS INC -CL A	BBB	3	0.38	0.58	0.38	0.58	52.3%
UNIFIRST CORP		3	0.23	0.48	0.39	0.59	82.7%
UNION PACIFIC CORP	BBB	3	0.49	0.66	0.38	0.58	60.7%
UNITED PARCEL SERVICE INC	AAA	1	0.48	0.65	0.49	0.66	79.5%
UNIVERSAL CORP/VA	BBB+	2	-0.02	0.32	0.11	0.40	41.7%
UNIVERSAL FOREST PRODS INC		3	0.90	0.93	0.91	0.94	58.8%
VF CORP	A-	3	0.53	0.68	0.63	0.75	65.6%
WALGREEN CO	A+	1	0.43	0.62	0.25	0.50	99.7%
WAL-MART STORES	AA	1	0.79	0.86	0.51	0.67	62.2%
WASHINGTON POST -CL B	A+	1	0.25	0.50	0.31	0.54	76.3%
WATSCO INC		3	0.76	0.84	0.72	0.81	85.7%
WATTS WATER TECHNOLOGIES INC	BBB	3	0.09	0.39	0.30	0.53	69.4%
WEIS MARKETS INC		1	0.16	0.44	0.10	0.40	100.0%
WENDY'S INTERNATIONAL INC	BBB+	2	0.38	0.58	0.45	0.63	70.3%
WEYCO GROUP INC		2	-0.13	0.24	-0.11	0.25	78.0%
WILEY (JOHN) & SONS -CL A		3	0.35	0.57	0.18	0.45	67.5%
WINNEBAGO INDUSTRIES		3	0.79	0.86	0.95	0.97	100.0%
WOLVERINE WORLD WIDE		3	0.64	0.76	0.75	0.83	87.8%
WOODWARD GOVERNOR CO		3	0.83	0.88	0.97	0.98	74.2%
YORK INTERNATIONAL CORP	BBB-	3	0.74	0.83	0.91	0.94	55.9%
Mean	A-	2	0.46	0.64	0.52	0.68	75.3%
Median	A-	3	0.49	0.66	0.50	0.67	73.9%

Source: Standard & Poor's Ratings Direct; *Value Line* data as of June 17, 2005

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
188 LOW RISK US INDUSTRIALS

Company Name	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Average 1993-2004	Average 1993-1995	Average 1996-2004
3M CO	19.27	19.96	14.33	23.18	34.74	20.45	28.84	28.97	22.67	32.69	34.63	32.74	26.04	17.85	28.77
ABM INDUSTRIES INC	11.90	12.50	13.31	13.86	14.76	15.35	15.22	14.78	9.56	12.50	21.78	6.88	13.53	12.57	13.85
ACETO CORP	3.55	12.72	13.13	11.49	9.97	12.11	9.46	9.90	6.39	6.94	12.00	14.14	10.15	9.80	10.27
ALAMO GROUP INC	25.12	19.95	16.49	9.32	13.37	3.86	5.68	9.68	9.15	5.06	5.86	8.79	11.03	20.52	7.86
ALBERTO-CULVER CO	14.11	14.08	15.09	15.77	18.53	16.11	15.65	17.12	16.08	17.23	16.85	11.93	15.71	14.43	16.14
ALBERTSONS INC	24.46	27.13	25.54	23.52	22.15	21.69	10.04	13.43	8.63	10.42	10.51	8.22	17.14	25.71	14.29
ALEXANDER & BALDWIN INC	11.69	12.24	8.70	9.79	11.59	4.38	9.17	11.48	15.76	8.11	10.56	11.78	10.44	10.87	10.29
ALICO INC	5.00	11.96	12.47	5.81	13.50	7.61	4.50	14.48	14.86	6.67	10.58	13.13	10.05	9.81	10.13
AMERON INTERNATIONAL CORP	-18.63	8.98	9.60	11.03	13.01	12.96	12.90	14.06	14.35	13.49	12.78	5.03	9.13	-0.02	12.18
ANDERSONS INC	20.80	25.36	15.54	9.18	5.60	12.59	10.00	11.54	9.79	10.73	10.56	15.34	13.09	20.57	10.59
APOGEE ENTERPRISES INC	2.92	10.94	13.53	16.86	-36.24	21.00	9.07	10.49	16.38	17.14	-3.24	9.63	7.37	9.13	6.79
APPLEBEES INTL INC	13.76	19.23	18.29	16.94	16.85	17.27	19.71	23.59	21.64	23.14	21.95	23.18	19.63	17.09	20.47
APPLIED INDUSTRIAL TECH INC	6.77	8.89	10.71	13.16	13.65	12.00	6.78	10.47	9.18	4.84	6.55	9.72	9.39	8.79	9.59
ARCHER-DANIELS-MIDLAND CO	11.40	9.75	14.60	11.60	6.19	6.43	4.41	4.87	6.16	7.81	6.53	6.70	8.04	11.92	6.74
ARCTIC CAT INC	25.89	25.17	10.98	14.28	14.79	13.10	4.51	16.21	16.26	17.73	16.27	@NA	15.93	20.68	14.14
AVERY DENNISON CORP	10.95	15.11	18.60	21.35	24.54	26.74	26.22	34.62	27.70	25.90	22.56	19.51	22.82	14.89	25.46
BADGER METER INC	8.49	11.61	12.09	14.90	16.70	18.47	21.35	16.08	7.79	15.96	14.68	16.16	14.52	10.73	15.79
BALDOR ELECTRIC CO	12.71	15.29	16.33	17.09	18.19	17.57	16.49	17.56	8.56	8.90	9.24	12.86	14.23	14.78	14.05
BANDAG INC	21.06	22.19	23.27	20.13	27.91	12.75	11.36	13.00	9.10	10.96	13.35	13.25	16.53	22.17	14.65
BANTA CORP	14.89	15.14	14.90	12.61	10.38	12.85	4.19	16.21	12.85	10.18	9.65	12.94	12.23	14.98	11.32
BARNES GROUP INC	4.73	20.42	23.29	22.77	23.92	18.67	15.50	18.68	9.56	13.34	12.46	10.07	16.12	16.15	16.11
BLAIR CORP	17.45	19.77	12.46	7.11	6.30	10.16	6.80	9.16	3.88	7.67	5.52	5.39	9.30	16.56	6.89
BLOCK H & R INC	29.53	15.39	20.54	4.69	33.51	17.92	22.09	23.14	34.16	38.25	39.56	31.69	25.87	21.82	27.22
BOB EVANS FARMS	14.64	14.41	7.28	8.67	10.39	12.42	11.77	11.46	13.84	13.88	12.10	*5.80*	11.39	12.11	11.15
BOEING CO	14.60	9.16	4.01	10.51	-1.49	8.87	19.42	18.93	25.87	25.04	9.07	19.27	13.61	9.26	15.05
BRADY CORP	13.71	13.67	17.83	15.67	16.12	12.79	16.11	17.19	9.24	9.01	6.44	13.71	13.46	15.07	12.92
BRIDGFORD FOODS CORP	21.34	20.27	19.03	14.66	15.57	18.27	18.40	15.33	11.00	2.04	2.27	0.05	13.18	20.21	10.84
BRIGGS & STRATTON	20.93	26.84	24.86	19.66	14.46	21.16	31.10	35.20	11.54	12.18	16.72	20.43	21.26	24.21	20.27
BRINKS CO	13.32	13.97	21.54	20.87	21.22	18.79	8.64	-33.28	3.34	5.83	6.71	20.78	10.14	16.28	8.10
BROWN-FORMAN -CL B	25.53	30.05	27.51	25.08	24.16	23.46	22.19	20.85	18.26	22.78	26.81	*24.80*	24.29	27.70	23.15
BRUNSWICK CORP	5.20	15.04	13.02	16.58	12.04	14.19	2.90	-8.09	7.78	9.36	11.15	17.78	9.74	11.09	9.30
BURLINGTON NORTHERN SANTA FE	18.43	23.21	5.10	16.14	13.84	15.84	14.26	12.52	9.62	9.63	9.46	8.89	13.08	15.58	12.24
CASEYS GENERAL STORES INC	12.44	13.54	13.87	12.33	13.52	14.24	12.92	10.78	8.95	10.22	8.64	8.09	11.63	13.28	11.08
CATO CORP -CL A	24.11	13.46	8.26	4.66	11.25	14.51	18.72	19.68	19.48	18.16	13.52	17.19	15.25	15.27	15.24
CBRL GROUP INC	15.50	14.30	14.27	11.96	14.12	14.23	8.80	7.28	5.87	11.27	13.50	13.41	12.04	14.69	11.16
CHURCHILL DOWNS INC	16.71	15.61	13.99	17.10	18.09	17.74	14.73	11.25	10.52	9.27	9.85	3.61	13.21	15.44	12.46
CLARCOR INC	16.90	18.57	17.69	18.04	16.97	17.92	17.82	17.77	16.23	15.80	15.91	16.02	17.14	17.72	16.94
CLOROX CO/DE	19.73	23.71	21.67	23.67	25.34	28.09	18.53	23.42	17.60	19.79	38.38	39.86	24.98	21.71	26.08
CONAGRA FOODS INC	19.30	19.97	7.59	26.02	23.92	12.60	13.19	19.86	18.94	17.27	18.88	16.40	17.83	15.62	18.56
COURIER CORP	9.10	12.97	15.29	6.75	10.72	16.88	15.61	16.97	17.85	18.36	19.04	16.41	14.66	12.45	15.40
CPI CORP	6.40	8.68	8.43	9.16	10.52	20.08	-3.27	15.45	11.28	11.94	2.30	-49.55	4.28	7.84	3.10
CSX CORP	11.67	18.87	15.50	18.51	14.85	9.22	0.88	9.60	4.83	7.56	2.98	5.11	9.96	15.35	8.17
CUBIC CORP	14.51	1.50	3.40	6.76	7.11	0.51	7.86	0.38	11.36	14.57	15.59	13.32	8.07	6.47	8.61
CURTISS-WRIGHT CORP	-1.97	12.90	10.98	9.06	14.37	13.38	16.00	14.98	19.65	11.86	11.74	12.34	12.11	7.30	13.71
CVS CORP	14.69	12.64	-32.49	4.93	2.72	15.12	19.90	19.66	9.31	14.52	15.03	14.09	9.18	-1.72	12.81
DANAHER CORP	15.10	19.45	20.39	29.97	18.03	16.13	17.10	17.76	14.27	17.72	16.13	18.05	18.34	18.31	18.35
DEB SHOPS INC	4.70	-2.82	-5.10	-5.06	8.66	18.15	23.59	19.63	15.92	15.14	7.03	9.61	9.12	-1.07	12.52
DELTA & PINE LAND CO	42.36	24.55	25.87	27.04	9.67	2.33	8.80	66.04	18.49	15.43	13.13	2.26	21.33	30.93	18.13
DONALDSON CO INC	16.88	17.57	18.76	19.30	21.42	22.84	24.09	25.87	25.21	24.76	22.97	21.33	21.75	17.74	23.09
DONNELLEY (R R) & SONS CO	9.69	14.05	14.39	-8.29	8.11	20.37	25.28	22.52	2.36	15.78	18.60	7.44	12.53	12.71	12.46
EATON CORP	17.54	23.91	21.83	16.88	21.93	16.91	26.36	18.00	6.92	11.77	14.25	19.28	17.96	21.09	16.92
ELKCORP	32.68	18.17	10.69	10.50	12.10	15.35	19.21	20.01	5.41	8.93	12.94	9.97	14.66	20.51	12.71
EMERSON ELECTRIC CO	18.53	21.91	20.17	19.92	20.83	21.89	21.92	22.61	16.49	17.88	17.85	18.35	19.86	20.20	19.75
ENGINEERED SUPPORT SYSTEMS	4.07	5.70	17.33	19.23	21.59	21.48	15.62	18.38	19.77	19.27	26.15	28.42	18.08	9.03	21.10

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
188 LOW RISK US INDUSTRIALS

Company Name	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Average 1993-2004	Average 1993-1995	Average 1996-2004
ENNIS INC	32.57	31.22	25.24	16.89	12.51	17.09	17.61	14.66	15.96	15.81	17.30	12.01	19.07	29.68	15.54
EW SCRIPPS -CL A	16.16	12.63	11.73	14.74	15.82	12.39	13.16	13.39	10.49	13.13	16.23	15.51	13.78	13.50	13.87
EXPEDITORS INTL WASH INC	12.20	14.01	15.94	18.87	24.79	24.42	23.69	25.78	25.05	23.98	20.86	21.49	20.92	14.05	23.21
FAMILY DOLLAR STORES	21.66	17.87	14.94	14.21	15.80	19.16	22.08	23.11	21.57	20.52	20.07	19.67	19.22	18.16	19.58
FARMER BROS CO	13.13	5.31	9.49	10.44	6.96	12.82	10.26	12.51	11.05	8.49	6.37	3.97	9.23	9.31	9.21
FASTENAL CO	26.98	31.78	33.85	29.54	27.98	27.61	26.20	25.18	17.88	16.18	15.63	20.77	24.97	30.87	23.00
FEDERAL SCREW WORKS	7.97	10.21	14.52	13.54	19.40	18.02	16.59	17.63	7.80	7.40	5.67	2.19	11.74	10.90	12.03
FEDERAL SIGNAL CORP	21.04	22.30	22.04	23.82	20.60	19.11	17.03	16.41	13.27	12.19	9.09	-0.55	16.36	21.79	14.55
FLEXSTEEL INDS	9.34	9.30	7.18	6.09	8.10	9.92	12.96	14.34	5.40	6.55	9.14	10.37	9.06	8.60	9.21
FLUOR CORP	17.33	16.99	17.48	17.29	8.57	14.41	6.71	7.77	1.62	19.56	17.08	15.45	13.35	17.27	12.05
FRANKLIN ELECTRIC CO INC	36.90	32.27	21.32	23.85	26.48	26.88	28.53	20.94	22.69	23.30	19.93	17.83	25.08	30.16	23.38
FREDS INC	9.40	7.53	2.38	4.94	7.86	6.63	7.57	9.72	10.37	12.02	12.46	9.24	8.34	6.44	8.98
FRISCH'S RESTAURANTS INC	8.21	3.68	3.56	1.83	7.93	8.40	11.23	13.90	13.55	14.93	14.11	13.20	9.54	5.15	11.01
G&K SERVICES INC -CL A	12.89	15.49	16.67	17.53	18.73	17.47	17.07	14.91	11.80	11.93	9.35	8.78	14.39	15.02	14.18
GANNETT CO	22.81	24.95	24.06	37.16	22.24	26.81	22.25	35.33	15.34	18.35	15.80	15.88	23.41	23.94	23.24
GATX CORP	10.42	12.56	12.76	12.05	-8.07	18.99	19.29	8.19	20.68	4.17	9.09	17.21	11.44	11.91	11.29
GENERAL DYNAMICS CORP	58.01	19.09	22.27	16.46	17.42	17.61	32.65	25.78	22.59	18.86	18.06	18.72	23.96	33.13	20.90
GENUINE PARTS CO	19.31	19.42	19.46	19.51	19.07	18.19	17.85	17.36	12.90	16.42	15.92	16.29	17.64	19.40	17.06
GORMAN-RUPP CO	16.04	15.74	14.69	14.19	14.08	14.53	14.87	14.35	14.03	8.15	8.59	7.78	13.08	15.49	12.28
GRAINGER (W W) INC	15.94	12.95	16.88	15.79	16.82	18.54	13.10	12.78	11.12	14.40	12.92	14.67	14.66	15.26	14.46
GRANITE CONSTRUCTION INC	2.15	11.23	14.54	12.33	11.34	16.65	16.83	15.82	12.69	11.29	12.61	10.80	12.36	9.31	13.37
HANCOCK FABRICS INC	5.78	10.64	9.06	12.14	14.46	3.87	8.85	13.63	16.01	17.55	13.63	1.35	10.58	8.50	11.28
HARLAND (JOHN H.) CO	23.88	26.48	21.63	-6.85	9.22	-11.63	25.76	16.86	20.88	24.05	22.87	20.80	16.16	23.99	13.55
HARSCO CORP	15.87	15.68	16.13	18.21	13.73	14.66	13.59	14.62	10.55	13.54	12.97	14.34	14.49	15.89	14.02
HARTE HANKS INC	-62.23	24.88	24.92	19.45	82.21	11.96	12.63	14.51	14.44	16.73	16.06	17.31	16.07	-4.14	22.81
HAVERTY FURNITURE	9.53	9.97	8.96	8.39	8.62	10.60	16.77	16.00	11.93	11.41	10.17	8.64	10.92	9.49	11.39
HEICO CORP	3.85	5.59	9.42	27.62	13.91	16.54	15.79	17.03	8.83	7.69	5.70	8.80	11.73	6.29	13.55
HILTON HOTELS CORP	9.98	11.14	14.51	7.01	7.22	16.15	21.97	17.80	9.69	10.32	7.64	9.90	11.94	11.88	11.97
HNI CORP	26.06	29.07	20.01	29.06	27.43	25.20	18.14	19.77	12.76	14.74	14.46	16.47	21.10	25.05	19.78
HORMEL FOODS CORP	16.59	19.15	17.29	10.47	13.79	17.24	19.76	19.85	19.52	17.94	15.69	17.47	17.06	17.68	16.86
HUBBELL INC -CL B	12.07	18.26	19.11	20.07	16.57	20.28	17.19	17.01	6.41	14.67	14.63	17.44	16.14	16.48	16.03
IDEX CORP	35.57	33.61	33.92	28.98	27.01	24.62	17.70	18.04	8.44	11.92	11.35	13.24	22.03	34.37	17.92
ILLINOIS TOOL WORKS	15.90	19.84	22.37	22.51	22.56	21.90	20.63	18.75	14.08	14.73	14.10	17.27	18.72	19.37	18.50
INTL SPEEDWAY CORP -CL A	25.23	23.59	23.92	20.51	18.82	13.94	8.92	5.44	8.82	12.82	15.64	19.44	16.42	24.25	13.82
JOHNSON CONTROLS INC	11.47	13.86	14.89	16.08	17.73	18.37	19.65	19.45	17.22	18.62	17.72	17.37	16.87	13.40	18.02
KELLWOOD CO	12.14	3.61	8.85	11.17	11.68	0.47	9.19	13.86	8.50	8.27	11.82	10.28	9.15	8.20	9.47
KELLY SERVICES INC -CL A	11.83	14.93	15.31	14.71	15.01	15.44	15.20	14.46	2.69	3.03	0.83	3.49	10.58	14.02	9.43
KIMBALL INTERNATIONAL -CL B	9.35	10.57	11.47	11.83	14.19	12.63	13.09	10.39	3.64	7.71	1.26	4.99	9.26	10.46	8.86
KIMBERLY-CLARK CORP	21.98	21.18	1.06	34.52	20.54	27.32	36.56	33.16	28.21	29.85	27.29	26.88	25.71	14.74	29.37
KNIGHT-RIDDER INC	12.21	13.85	14.33	23.89	30.81	22.79	18.94	18.26	11.44	18.65	20.07	22.22	18.95	13.47	20.78
LA-Z-BOY INC	12.53	11.81	11.77	12.89	13.36	16.47	16.26	10.06	8.77	14.52	0.45	6.69	11.30	12.04	11.05
LANCASTER COLONY CORP	26.31	27.92	27.44	25.35	25.65	24.69	23.05	23.91	20.62	19.13	21.46	14.10	23.30	27.22	22.00
LANCE INC	12.49	11.23	-3.23	12.90	16.21	14.82	13.50	12.36	13.49	11.11	10.07	13.04	11.50	6.83	13.05
LAWSON PRODUCTS	13.19	15.10	16.63	15.90	15.89	13.77	16.33	18.16	5.50	7.73	9.65	12.12	13.33	14.97	12.78
LEE ENTERPRISES INC	19.30	21.85	21.14	14.29	19.94	19.47	20.17	22.33	58.35	11.52	10.11	10.25	20.73	20.77	20.71
LEGGETT & PLATT INC	18.26	20.23	19.85	18.27	19.70	19.00	18.85	15.36	10.25	12.13	10.07	12.89	16.24	19.45	15.17
LENNAR CORP	13.35	13.61	12.34	13.50	14.89	24.95	21.63	21.72	28.94	28.04	27.36	25.85	20.51	13.10	22.99
LIBERTY CORP	12.16	5.80	11.93	6.22	11.76	2.61	8.28	9.50	2.85	5.89	4.51	8.46	7.50	9.96	6.68
LIFETIME HOAN CORP	16.81	17.10	11.77	14.01	12.54	14.60	4.43	4.15	3.75	2.87	10.24	9.47	10.15	15.23	8.45
LINCOLN ELECTRIC HLDGS INC	-23.69	28.44	23.46	20.58	20.61	20.20	15.69	17.38	17.67	14.42	12.02	15.27	15.17	9.40	17.09
LINDSAY MANUFACTURING CO	21.46	18.18	17.11	22.69	24.48	26.41	14.67	16.50	10.02	12.39	13.22	8.58	17.14	18.92	16.55
LONGS DRUG STORES CORP	10.39	9.52	8.83	10.89	10.15	10.36	10.28	6.47	6.71	4.36	4.16	5.07	8.10	9.58	7.61
LSI INDS INC	8.81	19.20	23.11	16.08	14.46	17.17	18.85	15.64	8.05	10.64	5.90	6.85	13.73	17.04	12.63
MARCUS CORP	11.44	11.82	18.17	11.69	9.81	7.51	7.08	6.57	6.49	5.68	6.45	6.30	9.08	13.81	7.51

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
188 LOW RISK US INDUSTRIALS

Company Name	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Average 1993-2004	Average 1993-1995	Average 1996-2004
MASCO CORP	11.38	9.42	-23.44	16.89	18.80	19.20	19.42	18.03	5.26	14.49	15.00	16.42	11.74	-0.88	15.95
MAY DEPARTMENT STORES CO	20.29	19.63	16.88	18.02	20.41	21.74	22.95	21.18	17.85	13.31	10.16	11.75	17.85	18.93	17.49
MCCLATCHY CO -CL A	8.57	11.30	7.41	9.19	12.89	8.90	9.79	9.67	5.93	12.77	13.22	11.81	10.12	9.09	10.46
MCCORMICK & COMPANY INC	22.04	12.78	19.33	10.26	23.35	26.57	26.81	37.08	35.65	34.07	31.60	26.08	25.47	18.05	27.94
MCDONALD'S CORP	18.27	19.15	19.58	18.99	18.58	16.93	20.39	20.99	17.51	10.04	13.55	17.40	17.62	19.00	17.15
MCGRATH RENTCORP	14.70	16.26	16.31	17.77	25.65	23.42	23.74	26.66	22.18	9.34	16.04	19.30	19.28	15.76	20.46
MCGRAW-HILL COMPANIES	1.32	23.40	23.32	41.38	20.79	22.89	26.26	27.34	20.86	28.70	29.12	27.28	24.39	16.01	27.18
MDC HOLDINGS INC	5.92	10.46	8.68	9.93	10.92	19.54	26.02	28.31	27.41	23.01	23.37	32.13	18.81	8.35	22.29
MEREDITH CORP	6.37	10.02	15.98	21.46	32.38	23.60	25.26	19.20	17.22	19.13	18.06	20.32	19.08	10.79	21.85
MET-PRO CORP	8.81	12.50	14.59	16.18	16.90	15.93	15.70	17.04	12.72	11.08	10.91	7.80	13.35	11.97	13.81
MINE SAFETY APPLIANCES CO	4.07	5.89	7.36	9.43	9.17	7.64	6.81	10.04	13.36	13.09	22.12	20.94	10.83	5.77	12.51
MODINE MANUFACTURING CO	18.15	24.44	18.67	17.35	17.94	16.89	14.01	9.70	4.59	6.57	7.24	9.90	13.79	20.42	11.57
MOVADO GROUP INC	12.58	16.86	9.83	11.20	12.70	13.45	8.73	13.52	10.32	9.82	8.95	8.90	11.40	13.09	10.84
NATURES SUNSHINE PRODS INC	28.25	27.20	31.77	32.19	30.97	33.06	23.49	21.10	18.44	7.86	6.33	20.26	23.41	29.07	21.52
NEW YORK TIMES CO -CL A	0.46	13.57	8.61	5.22	15.65	17.59	20.82	29.13	36.59	24.78	22.74	20.95	18.01	7.55	21.50
NIKE INC -CL B	17.64	21.57	25.17	28.49	12.45	13.69	17.90	17.79	18.23	18.90	21.56	*19.80*	19.43	21.46	18.76
NORDSON CORP	21.80	22.82	23.74	22.27	21.45	9.57	21.78	23.32	9.63	8.29	12.36	18.01	17.92	22.79	16.30
NORFOLK SOUTHERN CORP	12.40	14.35	14.98	15.71	13.84	12.92	4.03	2.93	6.30	7.31	6.25	12.34	10.28	13.91	9.07
NORTHROP GRUMMAN CORP	7.45	2.68	18.33	13.05	17.13	7.09	15.82	16.95	7.23	4.34	5.67	6.67	10.20	9.49	10.44
OSHKOSH TRUCK CORP	4.52	11.18	7.23	-2.43	8.25	12.89	21.21	21.78	15.70	15.75	16.29	19.53	12.66	7.64	14.33
PALL CORP	14.39	17.51	19.24	20.01	8.65	11.77	6.89	19.66	15.41	9.21	11.77	15.24	14.15	17.05	13.18
PARKER-HANNIFIN CORP	6.97	5.49	20.23	18.61	18.70	20.01	17.56	17.69	14.23	5.09	7.69	12.57	13.74	10.90	14.68
PENTAIR INC	13.57	13.24	16.95	14.28	15.87	16.64	12.53	5.70	3.25	12.25	11.94	12.64	12.40	14.59	11.68
PEPSIAMERICAS INC	21.38	19.30	22.62	21.95	0.69	14.32	-1.20	6.20	1.31	9.01	10.46	11.41	11.45	21.10	8.24
PIER 1 IMPORTS INC/DE	2.96	11.66	4.44	17.50	21.81	20.17	17.70	19.46	17.93	21.05	17.78	8.97	15.12	6.35	18.04
PULITZER INC	24.26	28.80	27.88	25.63	23.55	21.92	0.25	4.33	1.34	4.30	5.06	5.04	14.36	26.98	10.16
PULTE HOMES INC	14.99	26.10	7.93	22.59	6.43	11.78	17.69	16.10	17.10	18.01	20.12	24.76	16.97	16.34	17.18
QUIXOTE CORP	25.02	24.27	10.53	-18.57	-8.58	0.02	18.39	20.02	23.14	12.43	14.06	-24.42	8.02	19.94	4.05
RAVEN INDUSTRIES INC	18.15	14.06	13.09	14.52	13.63	9.98	11.58	12.51	17.69	20.29	22.19	26.99	16.22	15.10	16.60
RAYTHEON CO	17.03	14.51	19.28	17.12	7.02	8.12	4.19	1.30	-6.76	-1.31	4.05	3.82	7.36	16.94	4.17
REGIS CORP/MN	10.34	8.21	21.53	20.72	5.11	18.02	14.27	19.27	17.16	18.38	17.21	16.87	15.59	13.36	16.33
ROBBINS & MYERS INC	11.37	11.62	18.63	25.21	26.74	22.69	7.77	11.24	10.75	6.33	5.25	3.31	13.41	13.87	13.25
ROCKWELL AUTOMATION	19.60	20.09	20.79	18.06	14.21	-10.18	19.11	23.97	14.29	14.27	17.90	24.07	16.35	20.16	15.08
ROLLINS INC	30.63	27.99	19.26	11.27	0.89	5.83	9.41	12.70	20.65	30.77	31.17	38.04	19.88	25.96	17.86
RUBY TUESDAY INC	20.28	26.65	-1.30	11.90	13.35	16.83	16.18	23.05	18.84	23.63	23.60	20.90	17.82	15.21	18.70
RUSS BERRIE & CO INC	5.67	2.41	7.50	13.43	29.23	12.29	10.98	14.66	11.66	12.38	8.64	-6.15	10.22	5.19	11.90
RYDER SYSTEM INC	-3.35	14.49	13.12	-2.67	16.22	14.75	36.87	7.25	1.50	9.63	11.05	15.11	11.16	8.09	12.19
RYLAND GROUP INC	-1.75	6.59	-1.57	4.53	6.59	13.10	17.99	19.43	26.80	29.87	32.13	34.08	15.65	1.09	20.50
SCHAWK INC -CL A	3.13	23.61	7.30	-41.86	21.00	38.73	17.92	15.08	10.41	15.98	17.32	19.07	12.31	11.35	12.63
SKYLINE CORP	9.03	8.76	10.82	11.56	11.09	13.63	7.81	5.80	6.28	3.12	3.10	3.10	7.84	9.53	7.28
SMITH (A O) CORP	16.60	19.69	17.93	16.42	37.32	11.11	10.20	6.77	3.22	10.66	9.60	6.07	13.80	18.07	12.37
SMUCKER (JM) CO	13.41	14.75	10.97	10.89	12.24	12.06	8.27	11.30	11.70	13.72	9.54	*9.20*	11.50	13.04	10.99
SOUTHWEST AIRLINES	16.17	15.64	13.70	13.48	17.38	19.67	18.13	19.89	13.69	5.71	9.33	5.92	14.06	15.17	13.69
STANDEX INTERNATIONAL CORP	18.58	22.58	30.50	23.00	19.52	14.02	20.33	16.94	14.78	11.64	8.31	6.52	17.23	23.89	15.01
STANLEY WORKS	13.45	17.59	7.99	12.80	-6.04	21.58	21.36	26.42	20.18	20.37	11.71	35.28	16.89	13.01	18.18
STRIDE RITE CORP	21.02	6.66	-3.01	0.95	7.86	8.65	10.67	10.08	7.42	9.36	9.79	9.97	8.28	8.22	8.30
STURM RUGER & CO INC	33.55	29.02	20.13	24.52	18.52	15.24	20.99	15.94	8.02	5.60	9.10	3.39	17.00	27.57	13.48
SUPERIOR INDUSTRIES INTL	28.81	29.87	24.72	19.51	20.57	17.46	21.29	21.25	13.05	15.98	13.13	7.47	19.43	27.80	16.64
SUPERIOR UNIFORM GROUP INC	11.70	14.45	5.36	12.10	12.04	10.02	11.17	9.01	7.87	6.49	6.91	6.26	9.45	10.50	9.10
SUPERVALU INC	15.41	3.53	13.88	13.94	18.48	15.33	15.49	4.05	10.77	13.15	13.28	16.35	12.81	10.94	13.43
SYSCO CORP	18.40	18.23	19.05	19.24	21.05	23.56	26.03	28.45	30.54	31.77	35.95	38.10	25.86	18.56	28.30
TECUMSEH PRODUCTS CO -CL A	12.27	16.34	14.34	12.34	10.32	7.44	14.13	6.58	4.34	5.53	0.01	1.00	8.72	14.32	6.85
TELEFLEX INC	13.20	14.24	14.71	14.95	16.05	16.54	16.75	16.90	15.30	14.82	11.05	0.88	13.78	14.05	13.69
TENNANT CO	10.80	17.45	18.69	17.31	18.41	19.09	14.88	19.33	3.02	5.40	8.85	7.88	13.43	15.65	12.69

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
188 LOW RISK US INDUSTRIALS

Company Name	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Average 1993-2004	Average 1993-1995	Average 1996-2004
THOMAS INDUSTRIES INC	2.99	8.15	9.23	11.58	13.57	13.46	13.07	14.10	12.38	11.84	10.70	25.08	12.18	6.79	13.98
THOR INDUSTRIES INC	14.83	18.15	13.53	14.16	13.74	15.03	20.27	20.03	12.87	18.46	20.98	22.90	17.08	15.51	17.61
TOOTSIE ROLL INDUSTRIES INC	17.99	16.75	15.75	16.14	18.28	18.06	17.24	17.03	13.58	12.83	12.23	11.60	15.62	16.83	15.22
TORO CO	9.41	14.19	20.71	18.25	16.06	1.62	12.91	15.17	15.32	16.96	20.34	24.66	15.47	14.77	15.70
TREDEGAR CORP	6.34	22.66	14.05	23.51	24.10	23.63	15.43	25.61	2.00	-0.54	-5.79	6.29	13.11	14.35	12.69
TRIBUNE CO	17.79	19.40	20.29	25.88	23.84	20.15	52.90	4.51	1.54	10.42	13.57	8.27	18.21	19.16	17.90
TYSON FOODS INC -CL A	15.41	-0.16	15.90	5.78	11.75	1.40	11.23	7.02	3.18	10.92	8.85	9.77	8.42	10.38	7.77
UNIFIRST CORP	14.15	13.37	12.98	13.71	14.07	14.32	9.57	7.52	8.34	9.02	9.07	9.55	11.31	13.50	10.58
UNION PACIFIC CORP	14.81	10.90	16.46	12.39	5.25	-8.11	10.52	10.11	10.59	13.26	11.40	4.83	9.37	14.06	7.81
UNITED PARCEL SERVICE INC	21.13	21.96	21.29	20.74	15.17	26.26	8.99	26.42	24.27	28.67	21.23	21.34	21.45	21.46	21.45
UNIVERSAL CORP/VA	22.30	9.70	6.68	17.68	22.75	27.77	23.42	21.95	21.46	18.71	14.79	12.14	18.28	12.89	20.07
UNIVERSAL FOREST PRODS INC	20.30	16.10	18.13	19.37	15.72	17.18	15.49	13.52	13.19	13.83	14.13	14.69	15.97	18.18	15.23
VF CORP	18.02	16.52	8.76	15.76	18.02	19.45	17.01	12.07	6.14	19.32	21.93	21.18	16.18	14.43	16.76
WAL-MART STORES	23.92	22.84	19.94	19.16	19.78	22.37	23.75	22.02	20.08	21.60	21.83	22.08	21.61	22.23	21.41
WALGREEN CO	18.78	19.10	19.06	19.38	19.75	20.57	19.71	20.13	18.76	17.82	17.51	17.64	19.02	18.98	19.03
WASHINGTON POST -CL B	14.79	15.33	16.45	17.56	22.39	30.03	15.21	9.51	14.45	12.23	12.27	14.79	16.25	15.52	16.49
WATSCO INC	14.83	12.72	14.16	14.81	10.63	10.07	10.23	6.31	7.80	8.76	10.11	12.60	11.09	13.90	10.15
WATTS WATER TECHNOLOGIES INC	9.36	11.77	11.92	-13.86	15.84	15.08	9.44	7.74	11.02	11.97	9.11	10.08	9.12	11.02	8.49
WEIS MARKETS INC	10.29	10.16	10.22	9.80	9.39	9.63	8.81	7.91	6.80	10.98	9.68	9.97	9.47	10.22	9.22
WENDY'S INTERNATIONAL INC	14.04	15.15	14.67	16.63	11.65	10.95	15.62	15.48	17.96	17.66	14.72	3.00	13.96	14.62	13.74
WEYCO GROUP INC	8.18	10.15	11.02	13.11	14.42	14.88	16.64	15.27	13.11	16.65	18.66	18.55	14.22	9.78	15.70
WILEY (JOHN) & SONS -CL A	15.78	20.22	22.77	16.47	25.26	24.59	31.28	30.00	23.08	28.12	23.41	*20.10*	23.42	19.59	24.70
WINNEBAGO INDUSTRIES	12.07	21.62	30.81	12.04	20.11	20.29	33.29	29.85	22.89	28.23	25.55	34.25	24.25	21.50	25.17
WOLVERINE WORLD WIDE	10.80	13.53	14.29	14.82	15.92	14.30	10.24	3.19	12.72	12.89	12.94	14.84	12.54	12.88	12.43
WOODWARD GOVERNOR CO	6.29	-1.64	6.09	10.93	8.67	10.03	13.34	18.15	17.85	13.41	3.45	8.41	9.58	3.58	11.58
YORK INTERNATIONAL CORP	16.55	18.25	-16.68	21.05	6.64	19.82	10.50	14.40	6.18	11.42	1.57	9.86	9.96	6.04	11.27
Mean	14.31	16.07	14.71	14.98	15.77	15.72	15.94	16.07	13.40	13.98	13.60	13.59	14.8	15.0	14.8
Median	14.45	15.22	14.96	15.74	15.61	16.14	15.81	16.16	12.74	12.86	12.69	13.13	14.1	14.8	13.9
													14.6	14.6	14.5

Note: 2004 numbers in italics are *Value Line* forecasts.

Source: Standard and Poor's Research Insight, *Value Line*

RATIO OF DIVIDEND YIELD TO LONG TERM CANADA BOND YIELD FOR SIX CANADIAN UTILITIES[1/]
(Annual Average of Monthly Sample Median Values)

	Dividend Yield	30 Year Canada	Ratio
1996	5.49%	7.75%	70.9%
1997	4.45%	6.66%	66.8%
1998	3.96%	5.59%	70.9%
1999	4.60%	5.72%	80.4%
2000	5.10%	5.71%	89.2%
2001	4.24%	5.77%	73.5%
2002	3.81%	5.67%	67.4%
2003	3.76%	5.31%	70.8%
2004	3.59%	5.11%	70.3%
Means for 30-year Canada Bond yields:			
5.5% and below	**3.86%**	**5.26%**	**73.36%**
5.6 - 6.0%	**4.30%**	**5.79%**	**74.32%**
6.1 - 6.5%	**4.88%**	**6.26%**	**78.08%**
Over 6.5%	**5.22%**	**7.49%**	**69.52%**
All periods	**4.31%**	**5.89%**	**73.28%**

[1/] Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., Terasen Inc. and TransCanada Corp.

Source: Standard and Poor's Research Insight and Bank of Canada

Response of the Pre-Tax Return on Equity to a Change in Pre-Tax Bond Return Assuming Constant After-Tax Equity Risk Premium

Step 1:		
Initial Bond Return (Yield): 5%		
Pre-Tax Bond Return		5.00
Personal Income Tax Rate		45%
After-Tax Bond Return		2.75
Step 2:		
Initial Pre-Tax Equity Return: 10%		
Initial Pre-Tax Return on Equity		10.00
Return comprised of:		
Dividends	40%	4.00
Capital Gains	60%	6.00
Tax on Dividends	30%	1.20
Tax on Capital Gains	20%	1.20
After-Tax Equity Return		
Dividends		2.80
Capital Gains		4.80
After-Tax Equity Return		7.60
Step 3:		
After-Tax Equity Risk Premium		
Less After-Tax Bond Return		2.75
After-Tax Equity Risk Premium		4.85
Step 4:		
Increase Bond Return (Yield) to 6%		
Pre-Tax Bond Return		6.00
Tax Rate		45%
After-Tax Bond Return		3.30
Step 5:		
Calculate Required After-Tax Return on Equity:		
After-Tax Bond Return		3.30
Add After-Tax Equity Risk Premium		4.85
Required After-Tax Return on Equity		8.15
Step 6:		
Calculate Corresponding Pre-Tax Return on Equity:		
Tax Adjustment Factor [1/]		0.76
Pre-Tax Return on Equity	After-Tax ROE / Tax Adjustment Factor	10.72
Step 7:		
Calculate the changes in return:		
Change in Pre-Tax Equity Return	10.72 -10.00	0.72
Change in Pre-Tax Bond Return	6.00 - 5.00	1.00
"Sliding Scale"	Change in Pre-Tax Equity Return / Change in Pre-Tax Bond Return	72.4%

[1/] The after-tax return on equity is grossed up for personal income taxes at the rates and proportions of dividends and capital gains used in Step 2.

IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY

THEORY 1:

The overall cost of capital is invariant to changes in the capital structure. The cost of equity rises as the debt ratio rises, but the after-tax weighted average cost of capital stays the same.

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

ASSUMPTIONS:

Debt Cost = Current Cost of Long Term Debt for A rated utility
= 6.35%

Equity Cost = Recommended Return on Equity for Benchmark Utility
= 10.5%

Tax Rate = 34.5%

STEPS:

1. Estimate $WACC_{AT}$ @ 37.5% common equity ratio

   $WACC_{AT}$ = (6.35%)(1-.345)(62.5%) + (10.5%)(37.5%)
   = 6.54%

2. Estimate Cost of Equity at 33% common equity ratio with $WACC_{AT}$ unchanged at 6.54%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   6.54% = (6.35%)(1-.345)(67%) + (X)(33%)

   Cost of Equity at 33.0% Common Equity Ratio = 11.4%

3. Difference between Equity Return at 37.5% and 33% common equity ratios:
   11.4% - 10.5% = 0.9% (90 basis points)

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.35%
Equity Cost	=	Recommended Return on Equity for Benchmark Utility
	=	10.5%
Tax Rate	=	34.5%

STEPS:

1. Estimate $WACC_{AT}$ @ 37.5% common equity ratio

$$WACC_{AT} = (6.35\%)(1-.345)(62.5\%) + (10.5\%)(37.5\%)$$
$$= 6.54\%$$

2. Estimate $WACC_{AT}$ @ 33% common equity ratio (67% debt ratio)

$$WACC_{AT(\text{new debt ratio})} = WACC_{AT(\text{old debt ratio})} \text{ x } (1\text{-t x Debt Ratio}_{\text{new}})/(1\text{-t x Debt Ratio}_{\text{old}})$$

$$WACC_{AT(\text{new debt ratio})} = 6.54\% \frac{(1-.345 \text{ x } 67.0\%)}{(1-.345 \text{ x } 62.5\%)}$$

$$WACC_{AT(\text{new debt ratio})} = 6.41\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ at higher debt ratio:

$WACC_{AT(new\ debt\ ratio)}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

6.41% = (6.35%)(1-.345)(67%) + (X)(33%)

Cost of Equity at 33% equity ratio = 11.0%

4. Difference between Equity Return at 33% and 37.5% common equity ratios:
11.0% - 10.5% = 0.5% (50 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY

50-90 BASIS POINTS

OPINION

ON

RETURN ON EQUITY

FOR

GAZIFÈRE INC.

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies in more than 200 proceedings in Canada and the U.S., including the Régie de l'énergie du Québec. My professional experience is provided in Appendix F.

The purpose of my testimony is to recommend a return on equity ("ROE") for Gazifère Inc. for test year 2011, to evaluate the existing mechanism for adjusting the allowed ROE annually, and to recommend any changes to that mechanism as warranted.

B. SUMMARY OF CONCLUSIONS

My conclusions are as follows:

1. The existing automatic adjustment formula is not producing returns for Gazifère that meet the fair return standard. The fair return needs to be recalibrated and the automatic adjustment formula needs to be revised.

2. The sensitivity of the cost of equity to government bond yields is materially lower than the existing automatic adjustment mechanism implies. In addition, the cost of equity moves in the same direction as the utility cost of debt; this relationship has not been reflected in the automatic adjustment mechanism. As a result, the allowed ROEs have

decreased over time to a much greater extent than is justified and moved in the wrong direction in 2009.

3. The allowed return for Gazifère must meet all three requirements of the fair return standard, including the comparable returns standard. The fair return extends to both the capital structure and return on equity, that is, the overall return allowed must satisfy the fair return standard.

4. The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes.

5. Gazifère's common equity ratio of 40.0% is reasonable in light of the Company's business risks, and the capital structures maintained by both the major Canadian gas distributors and the smaller Canadian investor-owned gas and electric distribution utilities. The common equity ratio is materially lower than that maintained by relatively low risk U.S. gas and electric distribution utilities with which Gazifère competes for capital and whose returns are a relevant consideration for satisfying the comparable returns standard.

6. The fair return for a benchmark Canadian distribution utility is estimated at 10.75%. The benchmark return reflects the following:

   a. The return on equity is based on the results of equity risk premium and discounted cash flow tests.

   b. The equity risk premium test results are based on three separate approaches. The equity risk premium tests indicate the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	9.25%
DCF-Based	9.4%
Historic Utility	11.0%
Average	**10.0%**

c. Constant growth and multi-stage discounted cash flow tests, applied to a sample of benchmark low risk U.S. utilities, also support a cost of equity of 10.0%.

d. The allowance for financing flexibility is estimated in a range of 0.50% to 1.0%, or a mid-point of 0.75%. The addition of a 0.75% financing flexibility adjustment to a "bare bones" cost of equity based on the market-based equity risk premium and discounted cash flow tests results in a fair return for a benchmark Canadian distribution utility of 10.75%.

8. An incremental equity risk premium relative to the ROE for a benchmark distribution utility of no less than 0.50% is warranted for Gazifère. With an incremental equity risk premium of 0.50%, my recommended ROE for Gazifère for test year 2011 is 11.25%. The recommended ROE of 11.25% represents the recalibrated fair return for Gazifère to which the proposed revised automatic adjustment formula should be applied to determine the allowed ROEs for subsequent test years.

9. The automatic adjustment formula should be revised to lower the sensitivity to changes in long-term Canada bond yields from 75% to 50% and to add a second adjustment variable, namely, 50% of the change in long-term A rated corporate bond yield spreads. It is critical to recognize that the formula adopted has to be internally consistent with assumptions made in setting the allowed ROE for Gazifère for 2011. It is perhaps obvious that it would not be reasonable to implement the proposed formula without

adopting an allowed ROE that explicitly recognizes that the 2010 allowed ROE reflects a much greater sensitivity to changes in long-term Canada bond yields than the empirical evidence supports.

II. BACKGROUND FOR REVIEW OF GAZIFÈRE'S ROE

Since Decision D-99-09, issued February 1999, the annual allowed ROEs for Gazifère have been set using an automatic adjustment formula. The defining elements of the automatic adjustment mechanism are its sole reliance on forecast long-term Canada bond yields to set allowed ROEs and the underlying premise that the cost of equity changes by 75% of the change in forecast long-term Canada bond yields. If the formula were applied based on the February 2010 Consensus Economics, *Consensus Forecasts*, the allowed ROE for Gazifère would be 9.07%.[1]

From the inception of the formula in Canada in the mid-1990s,[2] the allowed ROEs for utilities regulated by the Régie de l'énergie, as well as for utilities in other Canadian jurisdictions, have tracked the downward trend in long-term Canada bond yields. Since the automatic adjustment formula was originally adopted, the overriding factor determining the allowed ROEs for Canadian utilities was the downward trend in long-term Canada bond yields, rather than factors which directly drive equity return requirements. Between 1995 and 2009, the forecast long-term Canada bond yield fell by 475 basis points; the corresponding average allowed ROEs fell by 335 basis points.[3] With the widespread adoption of similar automatic adjustment formulas, allowed ROEs in Canada converged to a relatively narrow range, with the result that comparisons among

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[1] The initial ROE adopted for Gazifère in D-99-09 was 10.0% based on a long-term Canada bond yield of 5.7%. The forecast of long-term Canada bond yields based on the February 2010 forecast of 10-year Canada bond yields of 3.9% (average of 3-month and 12-month forward forecasts of 3.7% and 4.1%) and the average January 2009 Bloomberg daily spread between 10-year and 30-year Canada bond yields of 0.56% is 4.46%. The application of the formula results in an ROE of 9.07%.

[2] The British Columbia Utilities Commission introduced the first formula (Order G-35-94, *In the Matter of Return on Common Equity BC Gas Utility, Pacific Northern Gas, West Kootenay Power*, June 1994). The National Energy Board adopted its multi-pipeline ROE formula in Reasons for Decision, RH-2-94 in March 1995.

[3] The reduction is slightly less than 75% of the decline in forecast long-term Canada bond yields largely due to the fact that the AUC did not apply its formula to the Alberta utilities for 2009.

the allowed ROEs as a reasonableness check were of limited value, as they were subject to an extensive degree of circularity.

The decline in long-term Canada bond yields experienced during the past 15 years reflects in large part a sea change in the Canadian economy characterized by a shift from huge government deficits and indebtedness to an unbroken string of government surpluses (commencing in 1997/98) and a steady reduction in the relative (to the size of the economy) amount of debt outstanding.[4] With the vast improvement in the government's finances and the reduction in government debt outstanding relative to the size of the economy came the decline in long-term Canada bond yields. The secular decline in long-term Canada bond yields reflects three factors: a reduction in the expected rate of inflation over the longer-term, the waning of investors' fear that inflation would reignite to levels experienced in the 1980s decade, and a declining supply of long-term government debt relative to demand.

Of these three factors, only the decline in the expected rate of inflation over the longer-term would directly translate into a corresponding decline in the cost of equity. The fear that inflation would reignite had taken the form of a premium that investors required to "lock in" investment in long-term bonds with fixed coupon rates. Investors in equities, in contrast, are not similarly locked in and thus equity investors did not demand the same "lock in" premium. In contrast to the fixed rates on debt, corporate earnings, which ultimately determine the returns to equity investors, are better able to keep pace with the rate of inflation. The elimination of the "lock in" premium as inflationary fears waned lowered the risk associated with investment in long-term government bond yields. In the absence of a commensurate decline in the cost of equity, the result was an increase in the market equity risk premium.

With respect to the third factor, strong demand for long-term government debt by institutions, particularly those seeking to match the duration of their assets and liabilities, creates an

[4] With the financial crisis and ensuing recession, the Federal government is now anticipating budget deficits for fiscal years 2009/10-2014/15.

imbalance in the supply of and demand for long-term government securities. The scarcity factor, in turn, leads to abnormally low long-term government bond yields. The reduction in long-term government bond yields arising from a demand/supply imbalance has no bearing on the cost of equity.

Layered over the secular decline in long-term Canada bond yields have been periodic "flights to quality" throughout the period the formulas have been in effect. A "flight to quality" occurs when investors flee from risky securities to the safe haven of the safest securities, long-term government securities. A "flight to quality" puts downward pressure on the yields of default-free securities, e.g. long-term government bond yields, and a corresponding increase in the cost of risky forms of capital. Since the introduction of automatic adjustment formulas, the capital markets have been characterized by multiple crises of varying proportions, including the "Asian Contagion" and ensuing Russian sovereign debt default in 1997-1998, the dot.com bust in 2000, the Enron bankruptcy in 2001, 9/11, the run-up to and the outbreak of the Iraq War in March 2003, and the global financial crisis dating from August 2007. The series of market crises and flights to quality during the period the formulas were in operation kept downward pressure on the level of long-term Canada bond yields, which in turn suppressed the level of allowed ROEs.

The application of the automatic adjustment formulas for 2009 clearly demonstrated that the existing formula also could produce incongruous results, that is, a decline in allowed ROEs at a time when the cost of capital was increasing. While the flight to quality had pushed both the actual and forecast yields on long-term government bonds lower during 2008, other capital market indicators were signaling a higher cost of capital.

Between October 2007 and October 2008, the yield on long-term A rated corporate bonds had jumped approximately 170 basis points, from approximately 5.6% to 7.3%. The yield on the TSX Composite rose by more than 1.5 percentage points, with the equity market falling 35% over the same 12-month period. The higher dividend yield, similar to the increase in corporate debt yields, pointed to a higher cost of capital.

In addition to the increase in the TSX Composite dividend yield, the increase in the cost of equity and a widening of the equity risk premium were reflected in the significant increase in the volatility in the equity markets, as represented by the Implied Volatility Index ("MVX") introduced by the Montréal Exchange in 2002. The Montréal Exchange states that the "MVX is a good proxy of investor sentiment for the Canadian equity market: the higher the Index, the higher the risk of market turmoil. A rising Index therefore reflects the heightened fears of investors for the coming month."[5]

During much of 2002-2007, prior to the onset of the financial crisis, the MVX was relatively stable, trading within a range of 8 to 24, and averaging 15. During 2008, the MVX rose sharply, peaking at almost 90 in November 2008, its highest level since inception, and averaging close to 60 during the 4th quarter. To put this in perspective, the MVX never exceeded 25 prior to August 2007. The increase in the MVX signaled higher risk aversion and an increase in the equity risk premium. Despite broad-based market indicators to the contrary, the application of the automatic adjustment formulas, tied to government bond yields, resulted in lower allowed ROEs for 2009 than for 2008.

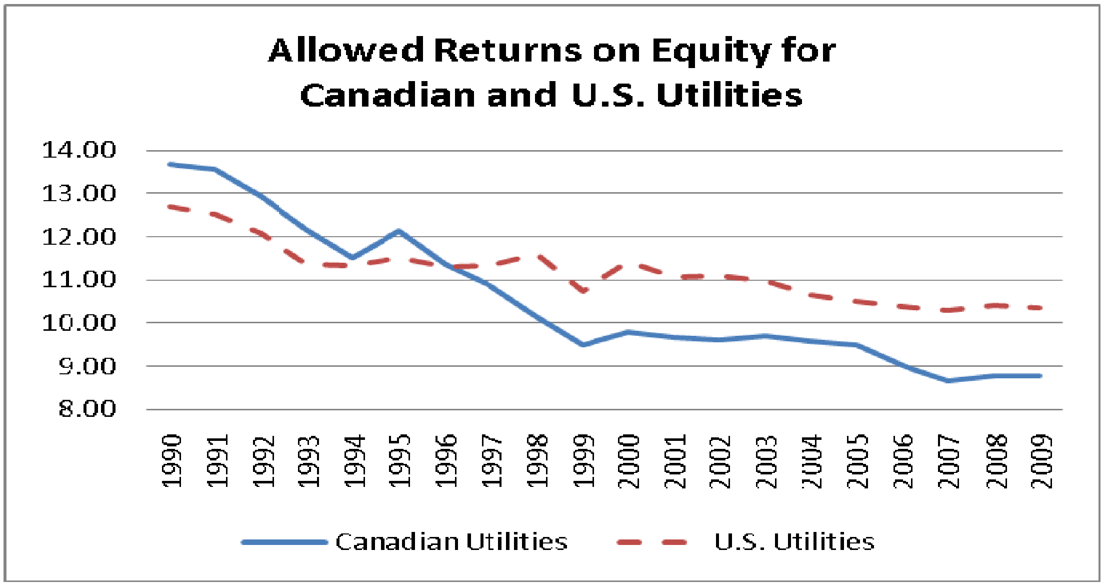
While the incongruity of the formula results during the financial crisis highlighted the problem with the formulas, it was not the onset of the financial crisis which caused the formula to go awry. It is the result of reliance on a formula governed solely by changes in the long-term Canada bond yield (with a high elasticity factor), rather than the composite of factors that bear on equity return requirements, that caused the allowed ROEs to diverge off course over time. The extent of that divergence can be assessed by a comparison of the allowed ROEs of Canadian and U.S. utilities.

[5] www.m-x.ca/indicesmx_mvx_en.php

This comparison is germane given (1) the significant integration of the Canadian and U.S. capital markets, (2) the similarity in the business (or operating environments) for distribution utilities in Canada and the U.S., and (3) the similarity in the regulatory models in the two countries.

Figure 1 below compares the allowed ROEs in Canada and the U.S. between 1990 and 2009.

Figure 1



Source: Schedule 2.

Figure 1 shows that allowed returns in the U.S. and Canada were comparable until automatic adjustment formulas tied to government bond yields became the norm (approximately 1997-1998) in Canada. With the widespread adoption of automatic adjustment formulas in Canada, a significant gap between the allowed ROEs in the two countries emerged, a gap which persisted through 2009. Between 1998 and 2009, Canadian utilities' allowed ROEs averaged 1.4 percentage points lower than those of their U.S. peers, whose allowed ROEs continued to be set using various tests and informed judgment. The average yield on long-term government bonds in the two countries over the same period differed by only nine basis points.

Since allowed ROEs in the U.S. are determined using various cost of equity tests, they can be used, retrospectively, to test the sensitivity of the utility cost of equity to changes in long-term government bond yields. When the quarterly allowed ROEs from 1995 (the year the initial automatic adjustment mechanism was applied in Canada by the BCUC) to 2009 are regressed against long-term Treasury bond yields lagged by six months,[6] the result indicates that the allowed ROEs changed by approximately 40 basis points for every one percentage point change in long-term government bond yields. By comparison, the typical automatic adjustment formula which has been relied upon in Canada, including the Régie's formula, assumes that the ROE changes by 75 basis points for every one percentage point change in long-term government bond yields and includes no other explanatory variables. The analysis strongly indicates that, with the benefit of hindsight, the cost of equity is significantly less sensitive to changes in long-term government bond yields than the automatic adjustment formulas assume.

The evidence that the formulas were producing returns that did not meet the fair return standard had been mounting for some time.

As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

[6] To take account of the fact that the date of the decision lags the period covered by the market data on which the ROE decision was based.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

In its June 2006 *Canadian Hydrocarbon Transportation System* report, the National Energy Board (NEB) reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they had "Buy" recommendations on utility stocks, the recommendations tended to reflect the prospects of the unregulated operations. Analysts also commented that companies had reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views.[7] Some market participants expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated:

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

In *Pipelines/Gas & Electric Utilities*, dated December 7, 2006, Karen Taylor, then equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns

[7] The NEB did not consult with analysts for the purpose of their 2008 report, in light of its then ongoing cost of capital proceeding for TransQuébec and Maritimes Pipeline.

as established by the formulas highlighted above [referring to the NEB, EUB,[8] BCUC and OEB[9] formulas] are confiscatory and likely violate the Fair Return Standard."[10]

With the unambiguous divergence between the trends in long-term government bond yields on the one hand and utility bond yields and the market cost of equity on the other during 2008 led other investment analysts to the conclusion that the formula had broken. In RBC Capital Markets' January 16, 2009 *Industry Comment* entitled "Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?", analyst Robert Kwan commented:

> With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).

Mr. Kwan recommended from a risk/reward perspective:

> We would focus on companies with the least exposure to the formula.

A February 23, 2009 report by Macquarie Research entitled *ROE Formula May Finally Bite the Dust* concluded that government bond yields bear little resemblance to any private company's cost of capital. The report also concluded that:

> Lack of comparability between allowed utility ROEs and returns on similar investments is driving the emerging capital access problem. In support of the argument the comparability criterion is not being met, utility customers and their expert witnesses like to point out that allowed returns for U.S. utilities are considerably higher than allowed returns in Canada. No matter how we slice the data, we concur with this opinion.

---

[8] Alberta Energy and Utilities Board, now the Alberta Utilities Commission.
[9] Ontario Energy Board.
[10] Studies commissioned by the Canadian Gas Association and the Canadian Energy Pipeline Association published in 2008 also came to the conclusion that the ROEs produced by the automatic adjustment formulas did not meet the fair return standard.

On March 19, 2009 the National Energy Board released its cost of capital decision for TransQuébec and Maritimes Pipeline (TQM). In that decision, the NEB expressed the view that:

> there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

The NEB also noted that:

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

Following its decision for TQM specifically, the NEB rescinded its RH-2-94 decision which adopted the automatic adjustment formula.[11]

BMO Capital Markets analyst George Lazarevski in *Pipelines and Utilities* (March 30, 2009) stated:

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.

[11] National Energy Board, *Reasons for Decision, Multi-Client, RH-R-2-94*, October 2009. It is of note that the NEB's decision was for years 2007 and 2008 and was rendered independently of the financial crisis.

On April 24, 2009, Scotia Capital commented:

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.
>
> Beginning with the National Energy Board in early 1995, Canadian energy regulators have largely adopted formula-based annual adjustments to utilities' allowed return on equity. These formula have been based on the capital asset pricing model. A base "risk-free" rate, represented by long Canada bond yields, is augmented by an equity risk premium, chosen to represent the business and financial risk of the utilities. The NEB's formula was created in 1994 and 1995, when Canada long bond yields reached over 9% at times, due to a range of factors, including ratings downgrades, large public sector deficits, and bearish domestic and international market sentiment towards Canadian government debt.
>
> As Canada's public sector reformed its finances, long Canada yields have come down, gradually but steadily, since early 1995. This led to a gradual decline in utility allowed ROEs, which has been a challenge for equity holders, and a challenge for utility management to offset by trying to "over-earn" the regulatory target, which is used to set rates.
>
> The onset of economic and financial market turmoil in late 2007 led to a further, more rapid decline in Canada yields, mimicking the global flight to the safety of top-quality sovereign debt, and reflecting widespread investor aversion to risk of all kinds. This triggered a decrease in Canadian utility regulators' formula-driven ROEs, to unprecedented low levels. However, utility bond spreads, and their cost of equity capital, were rising.
>
> Very recently, the NEB recognized these adverse and undesirable results, in what we view as a very significant Decision in the case of Trans Québec & Maritimes Pipeline. The NEB varied from its formula, which it had applied virtually universally to utilities in its jurisdiction since 1995. The ROE relief was material, lifting TQM's ROE from the formula-set 8.46% and 8.71% in 2007 and 2008 (on the NEB's deemed equity capitalization of 30%) to roughly 11.6% to 11.8%, based on the same capital structure and the embedded cost of debt.[12]

[12] Stephen Dafoe, "Falling Canada Yields and Utility ROEs", *Capital Points*, ScotiaBank Group, April 24, 2009.

In its December 2009 decision, the BCUC eliminated its automatic adjustment mechanism.[13] In so doing the Commission found the following:

> The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.
>
> In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI [Terasen Gas] for 2010, it would seem inconsistent to retain the adjustment mechanism.

The BCUC set the allowed ROE for Terasen Gas, the designated benchmark utility, effective July 1, 2009 at 9.50%, compared to 8.47% for the first six months of 2009. The corresponding ROEs effective July 1, 2009 for both the smaller gas utilities, Terasen Gas (Vancouver Island) and Terasen Gas (Whistler), were 10.0%, 50 basis points point higher than the ROE for the benchmark utility.

In its, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009, the Ontario Energy Board ("OEB"), in its assessment of the automatic adjustment formula (which was identical to the Régie's formula), concluded that:

> The existing formula approximates this relationship [between interest rates and the equity risk premium] 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 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.

[13] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure, Decision*, December 19, 2009.

> 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 [Fair Return Standard]. 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.[14]

The OEB also recognized that:

> 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. 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 1:1.5. Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."

The OEB reset the benchmark allowed ROE at a forecast long-term Canada bond yield of 4.25% at 9.75%. Under the previous formula, the benchmark allowed ROE would have been 8.41%.

With this backdrop, a review of the cost of capital for Gazifère is warranted, the allowed return should be rebased at a level which satisfies the fair return standard, and the automatic adjustment formula should be revised.

[14] The OEB's refined formula is discussed further in Chapter VIII.

III. FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[15] which are echoed in numerous regulatory decisions across North America, including the Régie's *Décision: Demande de modifier les tarifs de* Société *en commandite Gaz Métro à compter du 1er octobre 2009,* D-2009-156, dated December 7, 2009.[16] A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

The legal precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk.[17]

[15] The principal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

[16] The three requirements were summarized by the National Energy Board (RH-2-2004, Phase II) as follows:

> "The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
> - be comparable to the return available from the application of the 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)."

The three requirements were reiterated in the *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008, March 2009* (pages 6-7).

[17] See Appendix A for further discussion of the distinction between the capital attraction and comparable returns standards.

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities. A fair return preserves the financial integrity of the utility, that is, it permits the utility to maintain its creditworthiness, as demonstrated by the level of its credit metrics and debt ratings. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, may potentially degrade the quality of service or deprive existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers.

IV. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The analysis starts with the proposition that the fair return (which in this context encompasses both capital structure and ROE) for Gazifère should be determined on a stand-alone basis. The stand-alone principle encompasses the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the utility raising capital in the public markets on the strength of its own business and financial parameters. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources and avoid cross-subsidies. The stand-alone principle has been respected by virtually every Canadian regulator, including the Régie, in setting both regulated capital structures and allowed ROEs.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk relates largely to the assets of the firm. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine a fair rate of return on rate base. The first is to assess the "subject" utility's business risks, then establish a capital structure that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone investment grade debt rating; and (c) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of a single "benchmark" cost of equity to the subject utility without any adjustment to the ROE.

The second approach relies on acceptance of the utility's actual or proposed deemed capital structure for regulatory purposes. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is then compared against that faced by the proxy firms used to estimate the ROE requirement. If the total risk of the benchmark sample is higher or lower than that of the subject utility, an adjustment to their cost of equity would be required when setting the subject utility's allowed ROE.

Both of these approaches have been taken by regulators in Canada. The Régie has used the second approach, that is, it has adopted both different capital structures and risk premiums for the utilities that it regulates, including Gazifère, Gaz Métro and Hydro-Québec. The British Columbia Utilities Commission (BCUC) and the Ontario Energy Board (OEB) have also taken this approach.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard. Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards. The advantage of the second approach is that it is, in principle, compatible with the philosophy that the capital structure, within a reasonable range, is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital.

For Gazifère, the second approach has been adopted for the estimation of the fair return.

B. CONCEPT OF BENCHMARK UTILITY AND BENCHMARK ROE

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. In principle, the cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment only if the magnitude of the total risks of the sample and the specific utility is comparable.

In Canada, there are only seven publicly-traded Canadian utilities, six with conventional corporate structures,[18] and Gaz Métro, which trades as a limited partnership.[19] These companies are relatively heterogeneous in terms of both operations[20] and size.[21] The relatively small and heterogenous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

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[18] Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas and TransCanada Corporation.

[19] Gaz Métro's partnership unit prices were negatively impacted by the October 2006 announced change in the income tax treatment of income trusts with the result that its recent betas are not strictly comparable to those estimated for the conventional corporate regulated companies.

[20] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.

[21] Ranging from an equity market capitalization of approximately $66 million (Pacific Northern Gas) to $24 billion (TransCanada).

As a result, an alternative is to estimate the cost of capital for a benchmark, or average risk, Canadian utility. For the benchmark cost of capital to be applicable to a specific utility, the specific utility's total risk needs to be similar to that of the proxy companies selected to estimate the benchmark cost of capital. If it is not, the solutions include: (1) changing the specific utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the specific utility; or (3) some combination of (1) and (2).

While market data for the Canadian utilities provide some perspective on the fair return for a benchmark utility, a more accurate assessment can be made by reliance on a sample of U.S. utilities drawn from a much broader universe and selected using criteria that are designed to (1) identify companies that are of relatively similar risk to an average risk Canadian utility and (2) produce a large enough sample of companies to ensure reliable cost of equity test results. Since the majority of Canadian utilities, including Gazifère, are largely "pipes" and "wires" utilities, the sample of U.S. utilities which serve as a proxy for a benchmark Canadian utility was selected according to criteria designed to identify relatively low risk, distribution (gas and electric) utilities.

The ROE developed from both Canadian and U.S. proxy companies and market data is intended to represent the fair ROE for a benchmark Canadian distribution utility. For Gazifère, the applicability of the benchmark distribution utility ROE is dependent on its relative total (business plus financial) risk. To the extent that Gazifère's total risk differs materially from the benchmark (i.e., is of higher or lower risk than the average Canadian utility), the benchmark distribution utility ROE will need to be adjusted.

V. BUSINESS AND FINANCIAL RISK OF GAZIFÈRE

A. OVERVIEW

As noted above, the business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. Business risk arises from demand, competitive, supply, operating, political and regulatory factors. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is frequently designed around the inherent demand/competitive risks.

Business risks have both short-term and longer-term aspects. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term risks that are of primary concern to the investor.

Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in underlying fundamental risk factors including the competitive environment, energy policy, and regulatory philosophy.

Because regulated firms are generally regulated on the basis of annual revenue requirements, there has been a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, competitive factors and ratepayer resistance may forestall higher return awards when the risk materializes. Second, no regulator can bind his or her successors and thus guarantee that investors will be compensated for longer-term risks when they are incurred in the future.

Financial risk is the additional risk borne by the equity shareholder because the firm uses debt to finance a portion of its assets. As discussed in Chapter IV, the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return. Thus the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Further, as the degree of financial leverage rises, so does the risk of loss of financing flexibility, the risk of bankruptcy and the risk that the equity shareholder will not recover the full equity investment. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm.

B. BUSINESS RISK OF GAZIFÈRE

Gazifère is a relatively small gas distribution utility serving the municipality of Gatineau, including the sectors of Hull, Aylmer, Gatineau, Masson-Anger and Buckingham. Table 1 below provides some perspective on its relative size compared to the major Canadian gas distributors. As the table indicates, Gazifère is less than 5% of the size of the major gas distributors on all three measures, customers, deliveries and rate base.

Table 1

Gas Distributor	Customers (Thousands)	Deliveries (10^6 m^3)	Rate Base (Millions of $)
Gazifère	35	175	69
ATCO Gas	1,260	6,200	1,035
Enbridge Gas	1,900	12,200	3,800
Gaz Métro	175	5,800	1,850
Terasen Gas	845	4,300	2,500
Union Gas	1,310	13,900	3,200

A small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated. Negative events are likely to have greater impact on the earnings or viability of a smaller company. The impact of smaller size for utilities with rated debt is frequently exhibited in lower debt ratings for these companies despite financial parameters that are stronger than their larger peers.[22]

To illustrate, in its June 2009 rating report for FortisBC, an electric utility, DBRS called the company's small size a "challenge" and stated,

> "FortisBC is a small utility compared with the dominant utility in the province, the Crown-owned BC Hydro, and serves a rural and low-population density region in south-central British Columbia. To some extent, the small size and franchise area limit opportunities for growth, operating efficiencies, and economies of scale as they relate to PBR."

FortisBC, which had a rate base of over $900 million in 2009, despite better credit metrics than Terasen Gas, the benchmark BC utility, due to an allowed common equity ratio of 40% and an allowed ROE that is 40 basis points higher than Terasen Gas's, is rated BBB(High) by DBRS

[22] See also discussion of small size premium in Chapter VII.

and Baa2 by Moody's. Terasen Gas, by comparison, has ratings of A by DBRS and A3 by Moody's.

Gazifère's gross margin is largely derived from the residential and commercial sectors; Rates 1 and 2 account for approximately 32% and 63% respectively of its delivery margin. The remainder of its margin is derived predominantly from three large customers operating in a single resource-based industry, the pulp and paper industry. The contribution of pulp and paper customers has declined significantly over the past decade as the industry has been hurt by a strengthening Canadian dollar, rising input costs, declining demand for pulp and paper products and the sharp downturn in the U.S. economy. With the decline in the pulp and paper industry and growth in the residential and commercial sectors, Gazifère is less dependent on the industrial sector than it had been historically. Because of its proximity to Ottawa, Gazifère's market growth is partly dependent on growth in government employment.

In the Rate 2 class (largely residential), although Gazifère has experienced significant customer growth (close to 5% per year between 2000 and 2009), its deliveries to Rate 2 customers have only increased by 1.4% annually, as average customer usage has declined. The average Rate 2 per customer usage in 2009 was only 75% of what it was at the beginning of the decade. Reduction in per customer consumption reflects a combination of factors, including construction of more energy efficient homes, installation of more energy efficient appliances, a trend toward construction of more multi-family dwellings, and Gazifère's Demand Side Management (DSM) program. While Gazifère has a deferral account which provides protection from lost volumes arising from its DSM program, over the longer-term, lost deliveries lead to higher unit delivery costs, which make natural gas less competitive.

Gazifère competes with electricity for both residential and commercial customers and load. While natural gas has a price advantage to electricity in Gazifère's service area, the price advantage is smaller than in other provinces (e.g., Alberta and Ontario) due to Québec's relatively unique abundance of low cost hydroelectric generation capacity and a fixed price for heritage generation. The magnitude of the price advantage is dependent on the commodity price of natural gas, over which Gazifère has no control. The price of natural gas exhibits considerable volatility, with monthly “spot” prices (based on the Alberta Hub price) ranging from $2.55 per GJ to $10.80 per GJ in just the past two years. While at current commodity prices, natural gas enjoys a competitive advantage to electricity, during 2008, on average, the price differential between natural gas and electricity in Gazifère’s residential sector was minimal. Gas price volatility creates uncertainty for consumers, which encourages them to take measures to permanently reduce energy consumption or to seek energy alternatives. A permanent increase in the commodity price of natural gas has the potential to erode the competitive advantage of natural gas in Gazifère’s service area. Further, since electric heating is easier for developers to install in new construction, particularly in multi-unit dwellings, it has a built-in advantage in new construction.

Energy policy also favours electricity and renewable energy technologies over natural gas. Natural gas is not considered as environmentally friendly an energy option as hydroelectric generation or other renewable energy technologies. In 2006, legislation was passed to implement the provincial energy strategy. Bill 52, entitled *An Act respecting the implementation of the Québec Energy Strategy and amending various legislative provisions*, amended the Act respecting the Agence de l’efficacité énergétique, broadening the scope of the agency’s mission by making it responsible for promoting the development of new energy technologies for all forms of energy and all sectors of activity. The promotion and development of renewable energy technologies as alternatives to fossil fuels, including natural gas, has the potential to negatively impact Gazifère’s future operations.

The legislation also granted the Régie the power to implement an annual duty on fuel that distributors must pay into the Québec Green Fund. In 2007, Québec became the first province to levy a carbon tax, a tax to which natural gas, but not hydroelectric generated electricity, is subject. The imposition of a carbon tax on natural gas negatively impacts its competitiveness relative to electricity.

In December 2009, the provincial government announced an ambitious[23] greenhouse gas emissions reduction target (20% below 1990 levels by 2020), which will further favour renewable technologies over fossil fuels, including natural gas. In sum, the aggressive provincial climate change policy increases the business risks to which Gazifère is exposed.

With respect to Gazifère's regulatory framework, the Company benefits from a supportive regulatory framework which includes a number of deferral and variance accounts. The key deferral and variance accounts are for gas costs, weather normalization, lost gas stabilization, regulatory expense, DSM expense and volumetric variance, and Agence de l'efficacité énergétique dues. In short, the regulatory mechanisms mitigate Gazifère's short-term risks. They cannot, however, change the fundamental demand and competitive risks nor guarantee the recovery of the shareholders' equity investment in the longer term.

Gazifère has also been subject to Revenue Cap per Customer Comprehensive Performance Based Regulation (CPBR) since 2006. The plan sets the test year revenue requirement as the prior year's revenue requirement per customer multiplied by a projected inflation less productivity and stretch factors, multiplied by projected test year customers. To this sum are added or subtracted a cost of capital adjustment, pass through items, exogenous factors and the customers' share of productivity earnings. The performance-based methodology gives the utility an opportunity to earn higher returns by providing incentives to control costs and achieve efficiencies. The mechanism includes an asymmetric sharing mechanism; customers are credited with a share of earnings in excess of the allowed return, but do not bear any short-fall. In comparison to the traditional cost of service methodology, which was based on a single year budget, the five-year term performance-based methodology exposes the utility to higher risk of not achieving the allowed return.

[23] The government has acknowledged that its target is ambitious, given that close to 50% of total energy in Québec already comes from renewable sources.

In summary, Gazifère is a very small gas utility, with higher exposure to a single resource-based industry than most of the major Canadian gas distributors (ATCO Gas, Enbridge Gas, Terasen Gas, and Union Gas), and operating in an environment characterized by significant competition with alternative sources of energy, particularly electricity. With regard to the latter, only two of the five major gas distributors (Gaz Métro and Terasen Gas) face material competitive pressure with alternative energy sources in their core (residential and commercial markets). Gazifère faces higher business risks relative to the major Canadian gas distribution utilities, which translate into a higher required common equity ratio and/or a higher common equity return.

C. FINANCIAL RISK OF GAZIFÈRE

Gazifère is proposing the same common equity ratio of 40% that it has maintained and utilized for ratesetting purposes since 1998. The 40% common equity ratio compares to a median common equity ratio of 38.5% adopted for the five major Canadian gas distributors.[24] Gazifère is too small to have its debt rated by the debt rating agencies, as are a number of the smaller investor-owned gas and electric distribution utilities that would be of reasonably comparable business risk to Gazifère. For those with no stand-alone debt ratings, their capital structures have not been directly "tested" by the capital markets. Nevertheless, the allowed capital structures of other Canadian utilities that are most comparable in terms of size and business risk class to Gazifère provide a basis for assessing the reasonableness of Gazifère's 40% common equity ratio. As Table 2 below indicates, Gazifère's 40% equity ratio is in line with those adopted for smaller electric and gas distribution utilities in Canada.

[24] Four of the five major gas distributors also have some preferred shares in their regulated capital structures, which Gazifère does not.

Table 2

Company	Allowed Equity Ratio	Rate Base ($ million)	Debt Ratings
AltaGas Utilities	43%	$166	N/A
Maritime Electric [1/]	40.5%	$325 [2/]	BBB+ (S&P)
Natural Resource Gas	42%	$13	N/A
Pacific Northern Gas-West [3/]	40%	$130	BBB(low) (DBRS)
Terasen Gas (V.I.)	40%	$555	A3 (Moody's)
Terasen Gas (Whistler)	40%	$43	N/A

[1/] Based on actual forecast capital structure.
[2/] Estimated based on year-end 2008 net property, plant and equipment.
[3/] Applying for increase in common equity ratio to 47.5%.

Gazifère's common equity ratio is similar to those of smaller gas and electric utilities in Canada, but remains well below those maintained and allowed for U.S. natural gas distribution utilities. The average allowed common equity ratio for U.S. gas distribution utilities over the period 2006-2009 averaged 49%.[25] The median actual common equity ratio for the sample of benchmark U.S. distribution utilities based on the four quarters ended September 2009, rated A on average by S&P and A3 by Moody's was approximately 48% (See Schedules 5 and 15). The ratios maintained and allowed for U.S. distribution utilities, with which Canadian distribution utilities (including Gazifère) compete for capital, indicate that Gazifère's common equity ratio is relatively low.

[25] Regulatory Research Associates, *Regulatory Focus: Major Rate Case Decisions, January 2009-December 2009*, January 8, 2010.

VI. BENCHMARK DISTRIBUTION UTILITY ROE

A. CONCEPTUAL CONSIDERATIONS

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity: equity risk premium (including, but not limited to, the Capital Asset Pricing Model), discounted cash flow and comparable earnings tests. Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[26] Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions.[27] These considerations not only emphasize the importance of reliance on multiple tests, but also of benchmarking, or testing the reasonableness of the test results themselves against other relevant information.

It is also important to recognize that expressing the ROE in terms of a premium above either long-term Canada bond yields or corporate bond yields for the purpose of applying an automatic adjustment formula does not mean that the initial ROE need be estimated solely using a test or tests that might be defined as equity risk premium tests. For example, an ROE estimated using a

[26] For example, Bonbright states, “No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions.” (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[27] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> “Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.”

discounted cash flow model can be expressed or interpreted in terms of a premium above a yield or return on a lower risk fixed income security.

Each test has its own set of pros and cons. The discounted cash flow test directly measures utility return expectations but is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. The comparable earnings test explicitly recognizes that the objective of regulation is to emulate competition and measures returns on the same original cost basis on which utilities are regulated, but is subject to concerns around selection criteria and whether the results are representative of economic returns. The Capital Asset Pricing Model, framed in an elegant, simple construct, and, on the surface, with only three components, easy to apply, has an intuitive appeal. Nevertheless, it has its own set of challenges, which are summarized below.

The focus on the challenges of the CAPM is not to suggest that other tests are necessarily superior, but because Canadian regulators have, in recent years, favoured CAPM to the exclusion of other tests.[28]

1. The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor **should** require (in contrast to the return that the investor **does** require or what returns are actually available to investments of comparable risk).

2. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model typically assumes that the return on the market is <u>highly</u> correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem. Consequently the application of the test proceeds on an

[28] Both the BCUC and the OEB recognized the limitations of the CAPM in their respective 2009 cost of capital decisions cited in Chapter II above.

assumption which is directly in conflict with an assumption underpinning the theoretical model itself.

3. The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to the country from which the data are drawn and the time period over which they are measured.

4. The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change.

5. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The need to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

6. The achieved equity market risk premium in Canada is significantly influenced by historic behaviour of the long-term Government of Canada bond. The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that

the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

7. The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return.

The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a fair return.

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own 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.[29]

[29] I am strongly of the view that the comparable earnings test is the only test which measures returns in a manner compatible with the base (original cost) to which they are applied. However, I also recognize that the comparable earnings test is the most controversial, not only in terms of its applicability to the estimation of a fair return, but in terms of its application (e.g., criteria for selection of comparables, period over which returns should be measured, need for adjustments for relative risk). Therefore, for the sole purpose of this evidence, in order to limit the issues relevant to the estimation of a fair return, I have applied risk premium and discounted cash flow tests only.

B. EQUITY RISK PREMIUM TESTS

1. Conceptual Underpinnings

An equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

2. Risk-Free Rate

The application of equity risk premium tests require a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable.

For the purpose of applying the equity risk premium tests, the estimated 2011 long-term Canada bond yield is 4.7%. The 4.7% long-term Canada bond yield estimate relies on the February 2010

Consensus Economics, *Consensus Forecasts*' 4.1% 10-year Canada bond yield forecast for February 2011,[30] which, with a January 2010 average spread between 10-year and 30-year Canada bond yields of 0.56%, results in a forecast yield of 4.7%. The 4.7% long-term Canada bond yield is consistent with a gradual upward trend toward the forecast yield expected to prevail over the longer-term (2011-2019) of approximately 5.25%.[31]

3. Risk-Adjusted Equity Market Risk Premium Test

3.a. <u>Conceptual and Empirical Considerations</u>

The risk-adjusted equity market risk premium approach to estimating the required equity risk premium for a benchmark distribution utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required equity risk premium for a benchmark distribution utility. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor **should** require (in contrast to what the investor **does** require). Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the

[30] Consensus Economics does not provide a forecast of the 30-year Canada bond yield, nor does it provide a forecast of 10-year Canada bond yields for all of 2011.

[31] Consensus Economics, *Consensus Forecasts*, October 2009 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2011 to 2019. The spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.

beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing sole reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Appendix B.

3.b. Equity Market Risk Premium

3.b.(1) Superiority of Arithmetic Averages

When historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages, not geometric (compound) averages, should be used. The geometric average, which is appropriate for use in describing historic portfolio performance, represents the achieved return as if it had been a constant average annual return. Using the arithmetic average of all past returns recognizes the probability distribution of future outcomes based on past variations in annual returns. Expressed simply, the arithmetic average captures the unpredictability of future returns based on the volatility of past returns; the geometric average masks the historic volatility by smoothing over annual differences. (See Appendix B for further discussion).

3.b.(2) Income Returns versus Total Bond Returns

The application of the CAPM requires the estimation of the market return in relation to the risk-free rate. While government bonds are considered default-free, they are not risk-free; they are subject to interest rate risk. The total bond returns experienced include capital gains and losses resulting from changes in interest rates over time. The bond income return, in contrast, reflects only the bond coupon payment portion of the total bond return; it represents the riskless component of the bond return. In principle, using the bond income return more accurately measures the historic equity risk premium above a true risk-free rate.

3.b.(3) The Post-World War II Period

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, I focused on post-World War II returns, that is, 1947-2009, a period more closely aligned with what today's investors are likely to anticipate over the longer-term[32] as well as achieved returns and risk premiums over longer periods.

3.b.(4) Globalization and Relevance of U.S. Equity Market Experience

My estimate of the expected/required equity market risk premium was made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but should also take into account the U.S. equity market as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

[32] Key structural economic changes have occurred since the end of World War II, including:
1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

The historic Canadian equity and government bond returns each incorporate various factors that call into question whether they would be a realistic representation of expected risk premiums (e.g., capital held captive in Canada as a matter of policy, lack of equity market liquidity and diversity, and the higher risk of the Government of Canada bond market historically, which has since dissipated). These factors are set out in Appendix B.

One factor is the historic impact of the Foreign Property Rule (FPR), which capped the proportion of foreign investment that could be held by individuals (in RRSPs) and by pension funds. The combination of mediocre returns and small size of the Canadian market relative to the total global market (approximately 2%) put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. This cap had been as low as 10% of the book value of assets (from 1971 to 1990) and was at 30% when it was removed entirely in 2005.[33] From this perspective, historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases have declined from their 2007 peaks, in 2009 they were still close to $500 billion through November 2009. In mid-2009, although the total percentage of foreign assets in trusteed pension funds was less than 30%, the percentage of foreign equity to total equity was close to 50%.[34, 35]

[33] From 1957 to 1971 no more than 10% of income could come from foreign sources.

[34] Based on market value. Statistics Canada, Table 280-0003.

[35] Pension funds are increasingly investing in infrastructure assets outside of Canada. For example, in early 2009 a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board completed the acquisition of Puget Energy, an electric and gas utility serving northern Washington State. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.15% on a 46% common equity ratio, adopted in October 2008.

The relevance of the U.S. experience to the estimation of the risk premium from a Canadian perspective has increased as the relationship between Canadian and U.S. interest rates has changed. Historically, much of the difference between the achieved risk premiums in Canada and the U.S. arises from higher interest rates in Canada. With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) has declined. Consequently, the differential between Canadian and U.S. government bond yields and returns that existed historically fell. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points. From 1998 to 2009, the difference was approximately -9 basis points. With similar government bond yields in the two countries for more than a decade, the U.S. historic equity market risk premium is a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors.

On the equity side of the equation, the Canadian equity market composite is dominated by two sectors, financial services and energy. These two sectors alone accounted for close to 60% of the total market capitalization of the S&P/TSX Composite at the end of December 2009. In contrast to the S&P/TSX Composite, the historic U.S. equity returns have been generated by a more diversified and liquid market. In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Approximately 47% of Canadian portfolio investment in foreign equities at the end of 2008 was in the U.S.[36] The diversified nature of the U.S. equity market and the close relationship between the Canadian and U.S. capital markets and economies warrant giving weight to U.S. historical equity risk premiums in the estimation of the required equity risk premium for a benchmark Canadian distribution utility.

[36] Statistics Canada, *Canada's International Investment Position – Third Quarter 2009.* The U.S. portion of Canadian direct investment abroad at the end of 2008 was 49%.

3.b.(5) Historic Risk Premiums from 1947-2009

As previously indicated, in arriving at an estimation of the market risk premium, my point of departure was both Canadian and U.S. historic returns and risk premiums during the post-World War II period. The average U.S. and Canadian historic risk premiums during that period were as follows:

Table 3

Historic Risk Premiums Arithmetic Averages (1947-2009)		
	Versus Bond Total Returns	**Versus Bond Income Returns**
Canada	5.2%	4.9%
U.S.	6.3%	6.4%

Source: Schedule 6, page 1.

The achieved risk premiums reflect average equity market returns of approximately 12.0% and average income and total returns on long-term government bonds of approximately 7.0% in Canada (see Schedule 6). The latter are well in excess of the long-term Canada bond yields which are forecast to prevail going forward (4.7% for the test year and 5.25% over the longer-term).

3.b.(6) Comparison of Longer-Period Returns to Post-World War II Returns

A comparison of the longer-term equity market returns in Canada and the U.S. to the post-World War II returns demonstrates that the average nominal returns for the equity markets have not changed materially. Over the long-term, the equity market return in both countries (based on arithmetic averages) has been in the approximate range of 11.5%-12.5%.

Table 4

	Canada		U.S.	
	1924-2009	1947-2009	1926-2009	1947-2009
Equity Market Returns	11.6%	12.0%	11.8%	12.4%

Source: Schedule 6, pages 1 and 2.

3.b.(7) Historic Risk Premiums and Price/Earnings Ratios

The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

I have analyzed the trends in P/E ratios, equity market returns, and bond returns.[37] That analysis demonstrates:

(1) The increase in price/earnings ratios experienced during the market bubble of the 1990s has not resulted in a higher and unsustainable level of equity market returns. The arithmetic average equity returns in both Canada and the U.S. from 1947-1988 (prior to the increase in P/E ratios commencing in 1989) are actually higher than the average returns for the full 1947-2009 period.

[37] See Appendix B for further discussion.

(2) An analysis of rolling 10-year average equity returns reveals no upward or downward trend in equity market returns in Canada or the U.S. over the post World War II period.

(3) The observed decline in the experienced risk premium over the 1947-2009 period, particularly in Canada, is due largely to an increase in bond returns, not a decline in equity returns. As noted above, the historic bond returns in Canada (both total and income returns) were significantly higher (at approximately 7.0%) than the forecast yields on long-term Canada bonds of 4.7% for 2011 and 5.25% over the longer-term.

In summary, the P/E ratio analysis suggests that historic equity market returns in both Canada and the U.S. are reasonable estimates of the forward looking equity market return. In contrast, the Canadian historic bond total and income returns are both materially higher than estimates of expected bond returns, which strongly suggest that the historic achieved equity market risk premium in Canada over the period 1947-2009 understates a reasonable estimate of the forward-looking equity market risk premium.

3.b.(8) Impact of Inflation on Equity Market Returns

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. The approximately one percentage point lower forecast rate of inflation in Canada and the U.S. compared to the historic rates might suggest that expected nominal equity returns would be lower than they have been historically. An analysis of nominal equity returns, rates of inflation and real returns on equity in both countries shows that real equity returns have generally been higher when inflation was lower (see Appendix B). The negative relationship between the achieved real equity returns and inflation does not suggest that the expected nominal equity rates of return should be lower than the historic nominal returns as a result of lower expected inflation.

3.b.(9) Estimate of Equity Market Risk Premium

Given the longer-term equity market returns, the absence of any material upward or downward trend in the nominal historic equity market returns during the post World War II period, the P/E ratio analysis, and the observed negative relationship between real returns and inflation, a reasonable expected value of the future equity market return is a range of 11.5%-12.0%,[38] based on Canadian equity market returns and supported by U.S. equity market returns. The expected return on long-term Canada bonds, based on both the 2011 and longer-term forecasts of the 30-year Canada bond yield, is in the range of 4.7% to 5.25% respectively. The resulting expected equity market risk premium is approximately 6.75%.

3.c. Relative Risk Adjustment

3.c.(1) Total Market Risk

The market risk premium result needs to be adjusted to recognize the relative risk of a benchmark distribution utility. My analysis of the relative risk adjustment starts with the recognition that (1) investors are not perfectly diversified and (2) they do look at the risks of individual investments and expect compensation for assuming company-specific or investment-specific risk. It also recognizes that, while investors can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot. Thus, a risk measurement that reflects those considerations is relevant for estimating the benchmark distribution utility equity risk premium. These considerations support focusing on total market risk, as well as on beta. The latter is intended to measure solely non-diversifiable risk. The drawbacks of beta as the sole

[38] Over the three-month period, October 2009-December 2009, the average dividend yield on the S&P/TSX was 2.8%. The expected long-term growth rate for the index based on available analysts' forecasts for the companies in the Composite, is 11.4%, indicating an expected return (based on a constant growth discounted cash flow approach) of approximately 14.5%.

measure of risk, as well as the absence of an observable relationship between "raw" betas[39] and the achieved market returns on equity in the Canadian market, provide further support for reliance on other measures of risk to estimate the required equity return (see Appendix B).

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total risk of a benchmark distribution utility, I used the S&P/TSX Utilities Index as a proxy. I calculated the standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, including the Utilities Index, over five-year periods ending 1997 through 2009 (Schedule 8).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 8 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(2) Historic Raw Betas

Since beta is the risk measure that underpins the application of the CAPM, I also took account of utility betas to estimate the relative risk adjustment. Schedule 11 summarizes the "raw"[40] betas I calculated using monthly changes in price for individual publicly-traded Canadian regulated pipeline, gas distribution and electric utility companies, the TSE Gas/Electric Index, and the

[39] The "raw" beta refers to the simple regression between the monthly percentage changes in the price of a utility or utility index and the corresponding percentage change in the price of the equity market index (the S&P/TSX Composite).
[40] The term "raw" means that the beta is simply the result of a single variable ordinary least squares regression.

S&P/TSX Utilities Sector using monthly price data calculated over five-year periods ending 1993 through 2009.[41]

As Schedule 11 indicates, there was a significant decline in the calculated "raw" five-year betas of the individual regulated Canadian companies between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative). Following an increase in 2007 to 0.50, the "raw" betas for the individual regulated Canadian company betas again declined in 2008 to approximately 0.25 and remained at that level in 2009.

The observed levels and pattern of the calculated "raw" utility betas in 1999-2009 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the financial crisis and the accompanying plunge in the equity markets; and (4) the greater sensitivity of utility stock prices than the equity market composite to rising and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006). Over the longer-term (1970-2009), the "raw" beta of the Utilities Index using total returns has been approximately 0.50, as indicated in Section 3.c.(3) below.

3.c.(3) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded regulated Canadian company shares and of the utility index explain a relatively small percentage of the actual achieved market returns over time. A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2009[42] shows the following:

[41] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

[42] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2009.

Table 5

$$\text{Monthly TSX Utilities Index Return} = 0.0055 + 0.49 \left\{ \text{Monthly TSE Composite Return} \right\}$$

t-statistic	=		14.6
R^2	=	31%	

The relationship quantified in the above equation suggests a long-term beta of approximately 0.50. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 31%. That means 69% of the monthly volatility in share prices remains unexplained.

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly long-term Canada bond returns to the analysis indicates the following:

Table 6

$$\text{Monthly TSX Utilities Index Return} = 0.00198 + .41 \left\{ \text{Monthly TSE Composite Return} \right\} + .52 \left\{ \text{Monthly Long Canada Bond Return} \right\}$$

t-statistics	=		13.0	9.1
R^2	=	41%		

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (41% versus 31%). The second regression equation suggests that utility shares have had approximately 40% of the volatility of the equity market and over 50% of the volatility of the bond market, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility shares' volatility unexplained. To provide some perspective, the average actual annual return for the index from 1970-2009 was 12.25%. Of this average annual return, almost

2.5 percentage points was explained neither by volatility in the equity market nor the long-term government bond market.[43]

Using an expected annual equity market return of 11.5%, the low end of the 11.5%-12.0% range developed above, an annual long-term Canada bond return equal to the forecast longer-term 30-year Canada yield of 5.25%, and an annual "unexplained" return component equal to that achieved in the past (2.4 percentage points), the indicated utility return going forward is 10.0%. If, instead, the "unexplained" return component is assumed to be equal to the same proportion of the total return as was the case historically (approximately 20%), the expected utility return is 9.3%. When the average of the two utility returns (9.7%) is expressed as an equity risk premium above both the near-term and long-term forecast long-term Canada bond yields of 4.7% and 5.25% respectively, the indicated relative risk adjustment is approximately 0.70- 0.75.[44]

3.c.(4) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that regulated companies are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely, stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.

[43] The unexplained component of the achieved return is represented by the intercept in the equation.

[44] $\frac{9.7\% - 5.25\%}{11.5\% - 5.25\%} = 0.71; \quad \frac{9.7\% - 4.7\%}{11.5\% - 4.7\%} = 0.74$

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0.

The following table compares the reported Bloomberg betas (calculated using three years of weekly prices) ending January 2010 for the five major Canadian utilities to calculated "raw" weekly betas for the same three-year period. The Bloomberg betas suggest that the relative risk adjustment based solely on the most recent Canadian regulated company betas would be approximately 0.61. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of approximately 0.50 for Canadian utilities shown in Table 5 above results in a relative risk adjustment of 0.67.[45]

Table 7

Company	"Raw" Beta	Bloomberg Beta
Canadian Utilities	0.38	0.58
Emera	0.39	0.59
Enbridge Inc.	0.51	0.64
Fortis	0.48	0.64
TransCanada	0.44	0.60
Average	**0.44**	**0.61**

Source: Schedule 11 and Bloomberg.com.

A comparison of the reported *Value Line* betas [46] to the "raw" calculated betas for the sample of low risk U.S. distribution utilities relied upon in the application of the discounted cash flow (DCF) and DCF-based risk premium test shows a similar relationship. While the "raw"

[45] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.
[46] *Value Line* uses a five-year horizon and a weekly price change interval.

calculated weekly betas for the five-year period ending December 2009 averaged 0.55[47], the 4th Quarter 2009 betas reported by the widely disseminated *Value Line* averaged 0.67 for the sample (Schedule 15).

3.c.(5) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the table below:

Table 8

Relative Risk Indicator	**Relative Risk Factor**
Total Market Risk (Standard Deviations)	0.65-0.70
Relative Historic Returns and Betas: Canadian Utilities	0.70-0.75
Recent Adjusted Beta: Canadian Utilities	0.61
Long-term Adjusted Beta: Canadian Utilities Index	0.67

These results support a relative risk adjustment in the approximate range of 0.65-0.70.

3.d. Benchmark Distribution Utility Risk Premium and Cost Of Equity

I previously estimated the equity market risk premium at the 2011 forecast long Canada yield of 4.7% and at the longer-term yield of approximately 5.25% at approximately 6.75%. At an equity market risk premium of 6.75% and a relative risk adjustment of 0.65-0.70, the indicated equity risk premium is in the range of approximately 4.4%-4.7%. The cost of equity based on the risk-adjusted equity market risk premium test at the 2011 forecast long-term Canada bond yield of 4.7% is approximately 9.25%, before any adjustment for financing flexibility.

[47] The calculations of the sample betas are sensitive to the period over which the betas are calculated, the price interval chosen to estimate the betas (e.g., weekly versus monthly) and the market index selected (e.g., S&P 500 versus the NYSE Index). The betas calculated using monthly data are systematically lower than the betas calculated using weekly data for the low risk U.S. distribution utility sample.

4. DCF-Based Equity Risk Premium Test

The risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly. That is, it estimates an equity risk premium for the equity market as a whole, and then adjusts it for the relative risk of the utility. The discounted cash flow based ("DCF-based") risk premium test estimates the equity risk premium directly for regulated companies by analyzing regulated company equity return data.

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model and long-term government bond yields to estimate expected utility returns and risk premiums over time. Monthly cost of equity estimates were constructed for the period 1995-2009[48] using the DCF model and a sample of low risk U.S. gas and electric utilities as a proxy for a benchmark Canadian distribution utility.[49] The reasons for choosing U.S. companies generally and gas and electric utilities specifically as a proxy for a benchmark Canadian distribution utility are as follows:

First, there are only six publicly-traded Canadian utilities with conventional corporate structures and with a long-term stock trading history. The nature of the operations of these companies has in several instances changed materially over time. Second, there are insufficient forward-looking estimates of long-term growth rates for these companies that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums. A consensus estimate of growth expectations is critical to the application of the discounted cash flow model and to the ability to estimate the relationship between the cost of equity and interest rates.

Third, U.S. regulated companies are reasonable proxies for estimating the cost of equity for a benchmark Canadian gas distribution utility. The operating (or business) environments are

[48] The analysis comprises the full period over which automatic adjustment formulas for setting allowed ROEs have been in effect in Canada.
[49] The selection criteria for the proxy utilities and the construction of the DCF estimates are described in Appendix C.

similar, the regulatory model in the U.S. is similar to the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment, as indicated by relatively similar levels of interest rates, is comparable. Only relatively pure-play U.S. distribution utilities were selected; these utilities are in the same business risk category as the typical Canadian utility[50] and are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. The average debt ratings of the sample are A (S&P) and A3 (Moody's), similar to those of the universe of Canadian utilities with rated debt (Schedules 3 and 15). The median *Value Line* Safety rank of the U.S. distribution utility sample is 1; the Safety ranks of both of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and Enbridge Inc.) are higher, at 2.[51] To the extent that the business risks of the U.S. distribution utilities are viewed as of higher business risk than the typical Canadian distribution utility, the U.S. utilities have higher common equity ratios (lower financial risk). The average common equity ratio of the sample of U.S. distribution utilities (based on the average of the last four quarters ending September 2009) was approximately 48% (Schedule 5), compared to a typical common equity ratio for Canadian utilities of approximately 40% (Schedule 4). The benchmark U.S. distribution utility sample contains nine utilities, and is the same sample of companies used to perform the discounted cash flow test (see Chapter VI.C.).

The monthly DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[52] plus the expected dividend yield. The equity risk premium is equal to the difference between the sample average DCF cost of equity and the corresponding month-end 30-year Treasury bond yield.

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[50] All of the utilities in the proxy sample of U.S. utilities have an "Excellent" business profile, as do the majority of Canadian utilities whose debt is rated by S&P.
[51] The Safety rank represents Value Line's assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.
[52] The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

For the sample of U.S. distribution utilities, the DCF-based risk premium test indicates an average risk premium over the full 1995-2009 period of 4.3%; the corresponding average long-term government bond yield was 5.4%, approximately 70 basis points higher than the 2011 forecast long-term Canada bond yield of 4.7% (Schedule 12, page 1). From 1999-2009 (which corresponds to the period during which the Régie's ROE formula has been in effect[53]), the average risk premium was 4.6% with a corresponding average long-term government bond yield of 5.0% (Schedule 12, page 1).

For the entire 1995-2009 period, the data demonstrate that there has been an inverse relationship between the long-term government bond yield and utility equity risk premiums. A simple regression analysis between the monthly 30-year Treasury bond yields and the corresponding equity risk premiums indicates that, over the full period, the equity risk premium rose by 55 basis points when the long-term government bond yield fell by 100 basis points and, conversely, the equity risk premium fell by 55 basis points when the long-term government bond yield rose by 100 basis points (Schedule 12, page 2). Expressed in terms of cost of equity, the cost of equity rose (fell) by 45 basis points when the long-term government bond yield rose (fell) by 100 basis points.[54]

Based on this relationship, at the 2011 forecast 30-year government bond yield of 4.7%, the indicated equity risk premium is approximately 4.7%. The indicated cost of equity would be 9.4%.[55] However, this analysis reflects only the relationship between the cost of equity and government bond yields to the exclusion of other factors which impact on the cost of equity.

To capture the impact of other factors, I incorporated corporate bond yield spreads into the analysis. The magnitude of the spread between corporate bond yields and government bond

[53] Initially adopted for Gaz Métro in D-99-11 (February 1999).

[54] For the shorter period, (1999-2009), the equity risk premium increased (decreased) by 47% of the decrease (increase) in the long-term government bond yield (Schedule 12, page 3). In other words, the cost of equity as measured by the DCF test increased (decreased) by 53 basis points for every one percentage point increase (decrease) in the long-term government bond yield

[55] Based on the 1999-2009 regression, the estimated equity risk premium is also 4.7% and the cost of equity at a long-term Canada bond yield of 4.7% is 9.4% (Schedule 12, page 3).

yields is frequently used as a proxy for changes in investors' perception of risk.[56] I estimated the relationship among utility equity risk premiums[57] and the spreads between long-term utility[58] and government bond yields in conjunction with the change in the yield on long-term government bond yields. To estimate this relationship, I performed a second regression analysis using the same two time periods, 1995-2009 and 1999-2009 (Schedule 12, pages 2 and 3). The analysis indicated for both periods that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.

The 1995-2009 analysis showed that the equity risk premium increased or decreased by approximately 35 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately nine basis points for every 10 basis point increase or decrease in the utility/government bond yield spread (Schedule 12, page 2). By comparison, the 1999-2009 analysis showed an increase (decrease) in the utility risk premium of approximately 50 basis points for every one percentage point decrease (increase) in the government bond yield and a increase (decrease) of 10 basis points in the utility risk premium for every 10 basis point increase (decrease) in the utility/government bond yield spread (Schedule 12, page 3). Based on both periods, the analyses which include both the long-term government bond and the utility/government bond yield spread suggest that the cost of equity has increased or decreased by approximately 50-65 basis points for every one percentage point increase or decrease in the government bond yield and has also increased or decreased by approximately 10 basis points for every 10 basis point increase or decrease in utility/government bond yield spreads.

At the end of January 2010, the spread between long-term Canadian A rated utility bond and 30-year Government of Canada bond yields was approximately 160 basis points. At a 2011 forecast long Canada yield of 4.7% and a utility/government bond yield spread of 160 basis points, the

[56] Or, alternatively, risk aversion i.e., willingness to take risks.
[57] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[58] Based on Moody's long-term A-rated utility bond index.

two variable DCF-based equity risk premium model indicates a cost of equity before any adjustment for financing flexibility of 9.3% based on both the 1995-2009 and 1999-2009 two variable analysis (Schedule 12, pages 2 and 3).

The average cost of equity based on both the single and two variable DCF-based equity risk premium approaches over both periods is approximately 9.4%.

5. Historic Utility Equity Risk Premium Test

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking equity risk premium for a benchmark distribution utility. Similar to the DCF-based risk premium test, this test estimates the cost of equity for regulated companies directly by reference to return data for regulated companies. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

Over the longer-term (1956-2009),[59] the average achieved utility equity risk premium was 4.5% for Canadian electric and gas utilities in relation to total bond returns and 4.3% in relation to bond income returns respectively.[60] For U.S. gas utilities, the corresponding average historic equity risk premiums over the entire post-World War II period (1947-2009) were 5.8% and 5.9% respectively. For U.S. electric utilities, the 1947-2009 average risk premiums were 4.8% and 4.9% (see Schedule 13).

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns, as summarized for the three utility indices in the table below.

[59] The longest period for which Canadian utility data are available from the TSE.
[60] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2009.

Table 9

	Utility Equity Returns	Bond Total Returns	Bond Income Returns
Canadian Utilities	12.1%	7.6%	7.8%
U.S. Gas Utilities	11.9%	6.1%	6.0%
U.S. Electric Utilities	10.9%	6.1%	6.0%

Source: Schedule 13.

An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns (Schedule 14); the utility returns in both the U.S. and Canada have clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%. However, as noted in Section B.3.b(7) above and in Appendix B, the achieved bond returns (both total and income returns), particularly in Canada, are well above the levels forecast over the longer-term. The forecast 30-year Canada bond yield for the longer-term is approximately 5.25%. Compared to a utility return of approximately 11.5%, the indicated utility equity risk premium is approximately 6.25%. Using the forecast 2011 long-term Canada bond yield of 4.7% and a utility risk premium of 6.25%, the indicated utility cost of equity, before adjustment for financing flexibility, is approximately 11.0%.

6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility costs of equity based on the three equity risk premium methodologies are as follows:

Table 10

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	9.25%
DCF-Based	9.4%
Historic Utility	11.0%

The three risk premium tests indicate a benchmark utility cost of equity of approximately 10.0% before any allowance for financing flexibility.

C. DISCOUNTED CASH FLOW TEST[61]

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return, which is the rate that equates the price of the stock to the discounted value of future cash flows.

Although the DCF test, like the equity risk premium test, has flaws, it has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM indirectly estimates the cost of equity. In addition, the DCF model is a positive model; that is, it deals with "what is" as opposed to "what should be". The DCF model provides a widely used alternative to the CAPM; it is the principal model utilized by U.S. regulators.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. To estimate the DCF cost of equity, I utilized both a constant growth and a three-stage

[61] See Appendix D for a more detailed discussion.

model. In both cases, the discounted cash flow test was applied to a sample of U.S. distribution utilities that are intended to serve as a proxy for a benchmark Canadian distribution utility.[62]

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.)

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. In the application of the constant growth model, I have relied on two estimates of earnings growth: the I/B/E/S consensus of investment analysts' earnings forecasts and an estimate of the sustainable growth rate.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. For the sample of U.S. distribution utilities used in the DCF test (as well as the DCF-based equity risk premium test), the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1995-2009 period of analysis was 4.8%. That growth rate is lower than the expected long-term nominal growth in the

[62] Reliance on U.S. utilities was explained in the discussion of the DCF-based equity risk premium test in Chapter VI.B.4.

economy as a whole has been over the same period.[63] An expected growth rate that is close to that of the economy as a whole would not be out-of-line with the level of growth investors could reasonably expect for the relatively mature utility industries over the longer-term.

As an alternative to the consensus of investment analysts' earnings forecasts, I estimated DCF costs of equity for the sample based on sustainable growth rates derived from *Value Line* forecasts of returns on equity, earnings retention rates and earnings growth from external financing. The development of the sustainable growth rates is explained in detail in Appendix D.

The two constant growth models indicate a cost of equity of approximately 10.2% (Schedules 16 and 17).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy. The three-stage DCF model is fully described in Appendix D. The three-stage model indicates a cost of equity of approximately 9.75% (Schedule 18).

The two DCF models support a cost of equity, before adjustment for financing flexibility, in the range of 9.75-10.2% (mid-point of 10.0%).

D. ALLOWANCE FOR FINANCING FLEXIBILITY[64]

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale

[63] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1991-2009), has been 5.4% over the same period covered by the DCF-based equity risk premium test.

[64] See Appendix E for a more complete discussion.

of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle.

In the absence of an adjustment for financial flexibility, the application of a “bare-bones” cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite averaged 2.2 times from 1995-2009; the corresponding average market/book ratio of the S&P 500 was 3.2 times.[65]

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[66] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard.

The cost of capital, as determined in the capital markets, is derived from market value capital structures. The cost of equity has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the corresponding book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to

[65] The market to book ratio of the S&P 500 includes the Utilities. The market to book ratio of the S&P Industrials alone has been higher.

[66] Based on the DCF model as shown in Appendix E, footnote 22.

the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure that the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the "bare bones" cost of equity of no less than 100 basis points (See Appendix E and Schedules 19-21).

A reasonable adjustment for financing flexibility to the "bare bones" cost of equity estimated solely by reference to market-based tests (that is, without reference to the comparable earnings test) would be the mid-point of the indicated range of 50 to 100 basis points, i.e., 75 basis points. The addition of an allowance for financing flexibility of 75 basis points to the "bare-bones" return on equity estimate of 10.0% for a benchmark distribution utility, derived from both the DCF and equity risk premium tests, results in an estimate of the fair return on equity of 10.75%.

VII. EQUITY RISK PREMIUM FOR GAZIFÈRE

The final step in the ROE analysis is to determine whether, at Gazifère's proposed equity ratio of 40%, an adjustment to the benchmark distribution utility ROE is warranted.

Gazifère is a very small utility for which there are no directly comparable proxy companies with capital market data from which to estimate the equity risk premium that is required for a utility of its size. In the absence of market data for proxy utilities that are directly comparable, the quantification of the incremental equity risk premium required for Gazifère requires professional judgment.

The table below provides some perspective on the incremental risk premiums that have been adopted for other relatively small Canadian gas distribution utilities in conjunction with their capital structures. The comparison of the smaller utilities to the relevant benchmarks, while admittedly circular, indicates a typical equity risk premium for the smaller utilities (at similar capital structures) of approximately 50 basis points on average.

Table 11

Company	Rate Base ($Millions)	Equity Ratio	Benchmark Utility	Benchmark Utility Equity Ratio	Risk Premium to Benchmark
AltaGas Utilities	166	43%	ATCO Gas	39%	0% [1/]
Natural Resource Gas	13	42%	Enbridge Gas	36%	0.50% [2/]
PNG-West [3/]	130	40%	Terasen Gas	40%	0.65%
Terasen Gas (Vancouver Island) [4/]	555	40%	Terasen Gas	40%	0.50%
Terasen Gas (Whistler) [4/]	43	40%	Terasen Gas	40%	0.50%

[1/] Difference in business risk reflected in capital structure. AltaGas's higher common equity ratio relative to ATCO Gas is equivalent to approximately 25-50 basis points in ROE.
[2/] Combined difference in common equity ratio and ROE with benchmark is equivalent to approximately 100 basis points in ROE.
[3/] Currently applying for increase in common equity ratio to 47.5% and increase in equity risk premium to 75 basis points. Terasen Gas's allowed common equity ratio was raised from 35% to 40% in December 2009.
[4/] Coincident with the BCUC raising Terasen Gas's equity ratio to 40%, directed to file in next revenue requirements application the equity ratio that best reflects the long-term business risks.

On a stand-alone basis, Gazifère would unlikely be able to obtain a debt rating higher than BBB.[67] In comparison, the utilities that serve as the proxies for estimating the cost of equity for a benchmark distribution utility have debt ratings in the A category. An independent estimate of the equity risk premium that is required for Gazifère was made by comparing the cost of equity for a sample of BBB rated U.S. gas and electric utilities to the cost of equity for the benchmark sample of U.S. distribution utilities.

The sample of BBB rated utilities was selected according to the following criteria:

(1) Classified as a gas or electric utility by *Value Line*;

(2) Rated BBB-/Baa3 to BBB+/Baa1 by both Standard & Poor's and Moody's;

(3) Financial Risk Profile of "Significant" or better by Standard & Poor's.[68]

The companies which met the selection criteria are shown on Schedule 22.

Table 12 below compares *Value Line* betas, DCF costs of equity (constant growth based on analysts' forecasts and sustainable growth, and three-stage) and capital structures for the benchmark sample of distribution utilities and the sample of BBB rated utilities.

[67] Gazifère's stand-alone cost of debt is estimated based on a debt rating of BBB/BBB (low).
[68] Standard & Poor's assigns both business and financial risk profile rankings to all the utilities that it rates. There are six business risk profile rankings, ranging from "Excellent" to "Vulnerable", and six financial risk profile rankings, ranging from "Minimal" to "Highly Leveraged." Utilities in the two highest financial risk categories, "Aggressive" and "Highly Leveraged" were excluded in order to minimize the differences in cost of equity between the BBB and benchmark samples due solely to differences in financial risk.

Table 12

Sample	*Value Line* Betas		DCF Cost of Equity (Median)			Common Equity Ratio (2004-2008) (Average of Annual Medians)
	(4th Q 2009) (Median	(2005-2009) (Average of Annual Medians)	Constant Growth (Analysts' Forecasts)	Constant Growth (Sustainable Growth)	Three-Stage	
Benchmark	0.65	0.75	10.0%	9.9%	9.7%	46%
BBB rated	0.75	0.82	10.8%	10.4%	10.2%	46%
Difference in Cost of Equity	0.675% 1/	0.5%1/	0.8%	0.5%	0.5%	---

1/ At estimated market risk premium of 6.75%.

Source: Schedules 16-18 and 23-27

The application of both the CAPM[69] and the DCF models indicates a difference between the cost of equity for the benchmark and BBB rated samples in a range of 0.50%-0.80%. Since the book value capital structures of the two samples are identical, the differences in the samples' cost of equity can be attributed to business risk differences, rather than financial risk differences. In other words, no adjustments to the costs of equity for the samples need to be made to account for differences in financial risk. The comparison of the costs of equity for the two samples supports an equity risk premium for Gazifère within the range estimated for the two samples.

An alternative approach to estimating the incremental ROE is by reference to the studies on small size and returns conducted by Ibbotson Associates Inc.[70] These studies have quantified the impact of a firm's small size on the required return by an analysis of the relationship between betas and historic returns for companies of different sizes. The analyses indicate that small companies tend to exhibit higher betas than larger companies. In the Ibbotson classification of stocks, if Gazifère were a stand-alone publicly traded stock, it would be a Micro-Cap stock (market value of equity of less than $450 million). By comparison, both the typical publicly-traded Canadian regulated company and benchmark U.S. distribution utility used to estimate the

[69] The differential based on the CAPM would be higher if the sample betas were calculated using monthly, rather than weekly, price changes.
[70] Morningstar, *Ibbotson SBBI 2009 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2008*, pages 89-110.

benchmark distribution utility ROE would be a Mid-Cap stock (market value of equity in the range of approximately $1.8-$7.4 billion; see Schedule 19). Ibbotson's analysis indicates the betas of Micro-Cap stocks have been approximately 0.32 higher than those of Mid-Cap stocks. An incremental beta of 0.32, when applied to a market risk premium of 6.75%, supports an incremental equity risk premium of over 200 basis points (6.75% x 0.32) for a Micro-Cap company, e.g., Gazifère.[71]

Based on this analysis, an incremental equity risk premium relative to the ROE for a benchmark distribution utility of no less than 0.50% is warranted for Gazifère. With an incremental equity risk premium of 0.50%, my recommended ROE for Gazifère for test year 2011 is 11.25%.

VIII. AUTOMATIC ADJUSTMENT MECHANISM

The key advantages of an automatic adjustment mechanism are as follows:

1. It reduces the regulatory burden imposed by the annual determination of ROEs.
2. It results in increased predictability of the allowed returns;
3. It avoids any potential arbitrariness of the outcome.

In Decision D-2009-156 the Régie noted the first advantage of relying on an automatic adjustment formula to set allowed ROEs. I do not disagree that an automatic adjustment formula can be a useful tool, provided that the ROEs it produces meet the three requirements of the fair return standard.

[71] Ibbotson's industry-by-industry analysis shows that the conclusions regarding the firm size effect apply to regulated companies as well as unregulated companies. Based on 82 years of data, Ibbotson's analysis shows that the returns for small publicly-traded electric, gas and sanitary utilities have been approximately 1.5 and 3 percentage points higher on a compound and arithmetic average basis respectively than those of large utilities. Morningstar, Ibbotson SBBI, *2008 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2007*, pages 154-155.

Any ROE formula should be governed by three criteria:

1. Accuracy
2. Simplicity
3. Transparency.

The criterion of accuracy relates to the ability of the formula to reasonably quantify changes in the cost of equity over time. The results of any formula, no matter how complex, will only be an approximation of the cost of equity. Thus, the importance of accuracy should be weighed against the other two criteria. While the cost of equity and its determinants are complex, simplicity, both in terms of understanding the results and the application of the formula itself, is an important consideration to stakeholders, including ratepayers. Transparency simply means that the values of any variables that are used in the implementation of the formula are clearly defined, independently produced and easily verifiable.

As discussed in Chapter II, the existing automatic adjustment formula needs to be revised. In constructing a revised formula, the long-term government bond yield remains a relevant component, as long as (a) the sliding scale factor adopted reasonably reflects the relationship between long-government bond yields and the cost of equity and (b) the government bond yield is supplemented with a variable which more directly captures movements in the cost of equity.

An obvious potential complementary explanatory variable for long-term Government of Canada bond yields in an ROE formula is the spread between government and corporate bond yields.[72] Since both debt and equity holders have financial claims on the same cash flows of a

[72] Changes in dividend yields are another alternative. The major drawbacks of using dividend yields in a formula are: (1) there is no “preset” index of comparable companies whose dividend yields could be tracked. Stakeholders would need to agree on a sample of companies which would serve as a proxy for a benchmark utility and (2) a change in dividend yield may signal a change in investor growth expectations rather than a change in the cost of equity.

corporation, all other things equal, it makes logical sense that changes in a firm's cost of equity will track changes in its cost of debt.

Corporate bond yield spreads are a widely used variable for explaining and estimating equity returns. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[73]

The relationship between the equity risk premium, long-term government bond yields and corporate bond yield spreads for regulated companies was tested two ways. First, the allowed ROEs adopted for U.S. utilities were used to test the sensitivity of the utility cost of equity to changes both in long-term government bond yields and utility bond yield spreads. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

Quarterly allowed ROEs from 1995 (the year the initial automatic adjustment mechanism was applied in Canada by the BCUC) through 2009 were regressed against long-term Treasury bond yields and the spread between A rated utility and Treasury bond yields.[74] The results of the analysis indicate that the allowed ROEs increased or decreased by 47 basis points for every one percentage point increase or decrease in the long-term government bond yields and increased or decreased by 27 basis points for every one percentage point increase or decrease in utility bond yield spreads.[75]

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[73] Examples include: Chen, N. F., R. Roll and S. A. Ross, 1986, "Economic Forces and the Stock Market", *Journal of Business*, 59, pages 383-403 and Harris, R.S. and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Summer 1992, *Financial Management*, pages 63-70.

[74] The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based.

As noted in Chapter II, excluding the spread as a second explanatory variable, the regression indicates that the allowed ROEs changed by approximately 40 basis points for every one percentage point change in long-term government bond yields.

[75] The regression is: 7.91 + 0.47 x 6 Months Lag of 30 Year Treasury + 0.27 x 6 Months Lag of Spread.

The relationship between the cost of equity, long-term government bond yields and corporate bond/government bond yield spreads was also tested, as discussed in Chapter VI.B.4., using the discounted cash flow approach applied consistently over time to the benchmark U.S. distribution utility sample. To summarize, over the period 1995-2009, the regression analysis indicated that the cost of equity increased (decreased) by approximately 65 basis points for every one percentage point increase (decrease) in the long-term government bond yield and increased (decreased) by approximately 90 basis points for every one percentage point increase (decrease) in the utility/government bond yield spread.[76] Over the period 1999-2009, with 1999 corresponding to the year the Régie's automatic adjustment formula was first implemented, the cost of equity increased (decreased) by 53 basis points for every one percentage point increase (decrease) in the long-term government bond yield and increased (decreased) by approximately 100 basis points for every one percentage point increase (decrease) in the utility/government bond yield spread.[77]

The greater sensitivity of the DCF-based estimates of the cost of equity to changes in the spreads than the allowed returns is understandable for at least two reasons. First, the allowed returns are likely to reflect the application of various tests, which would tend to mute the true relationship between the cost of equity and the spread. Second, the correspondence from a timing

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Incorporating utility bond yields directly into the analysis by regressing the quarterly allowed ROEs against long-term A rated utility bond yields indicates that the allowed ROEs have increased (decreased) by approximately 46 basis points for every one percentage point increase (decrease) in the A rated utility bond yield.

[76] The regression for 1995-2009 using ROEs (rather than risk premiums) as the dependent variable is: ROE = 4.75 + 0.66 X 30 Year Treasury (t-stat of 15.26) + 0.92 X Utility/Government Bond Yield Spread (t-stat of 13.64); R^2 of 63%.
Using the long-term government bond yield as the sole independent variable, the ROE increased (decreased) by 45 basis points for every one percentage increase (decrease) in the long-term government bond yield.

[77] The regression for 1999-2009 using ROEs as the dependent variable is: ROE = 5.28 + 0.53 X 30 Year Treasury (t-stat of 7.62) + 0.98 X Utility/Government Bond Yield Spread (t-stat of 12.65); R^2 of 63%. Using the long-term government bond yield as the sole independent variable, the ROE increased (decreased) by 53 basis points for every one percentage increase (decrease) in the long-term government bond yield.

perspective between the costs of equity and the utility bond yields is less precise using the allowed returns as the proxy for the cost of equity than the DCF-based costs of equity.

The two analyses together support the conclusions that:

1. The sensitivity of the ROE to changes in long-term government bond yields is materially lower than the 75% factor in the original formula;

2. Although the two analyses produce different estimates of the sensitivity, the ROE is positively related to the change in utility/government bond yield spreads.

Based on the results of the above analyses, I recommend that the Régie's automatic adjustment formula be revised as follows:

1. Reduce the relationship between the forecast long-term Government of Canada bond yields and the benchmark ROE from 75% to 50%; and

2. Add a second explanatory variable, corporate bond yield spreads, to the original formula with the same 50% sliding scale factor.

The resulting adjusted formula can be expressed as:

$$\mathbf{ROE_{New} = Initial\ ROE + 50\%\ X\ (Change\ in\ Forecast\ GOC\ Bond\ Yield) + 50\%\ X\ (Change\ in\ Corporate\ Bond\ Yield\ Spread)}$$

The proposed revised formula is analogous to the automatic adjustment formula that was adopted by the Public Utilities Commission of the State of California (CPUC) in May 2008 to set the

ROEs for the utilities under its jurisdiction.[78] The California adjustment mechanism adjusts the ROE by 50% of the change in utility bond yields.[79] It is virtually identical to the refined automatic adjustment formula adopted by the OEB in EB-2009-0084.[80]

Under the revised formula, the forecast long-term Government of Canada bond yield would be estimated in a similar way as it was under the original automatic adjustment formula. For Gazifère, the forecast long-term Canada bond yield would be estimated using the October Consensus Economics, *Consensus Forecasts* of 10-year Government of Canada bond yields plus the September actual average daily spread between 30-year and 10-year Government of Canada bond yields.[81] The relevant corporate bond yield spreads would be calculated using the actual difference between the yields on the long-term A rated Corporate Bond Index available from TSX Inc. and the yields on long-term Canada bonds prevailing at the time of the *Consensus Forecasts*.[82]

Schedule 28 shows what the National Energy Board's multi-pipeline ROEs would have been under this revised formula had it been adopted initially, compared to the ROEs produced by the formula actually adopted in *Reasons for Decision*, RH-2-94, May 1995. I used the NEB ROEs for comparative purposes, as the NEB's formula is virtually identical to the Régie's formula, was

[78] Public Utilities Commission of the State of California, *Decision Establishing a Multi-Year Cost of Capital Mechanism for the Major Energy Utilities*, May 29, 2008.

[79] Previously the CPUC had conducted annual cost of equity reviews. Under the new approach, it will conduct cost of equity reviews every three years, with the automatic adjustment mechanism used to set ROEs during the interim years. The utility bond yields to be used in the adjustment mechanism for each utility will be governed by the specific utility's debt rating, that is, if the utility's debt is rated A, its ROE will be adjusted by 50% of the change in A rated utility bond yields. The operation of the mechanism is also subject to a trigger of 100 basis points. The ROEs will not be adjusted unless the relevant long-term utility bond yields change by more than 100 basis points.

[80] The principal difference is that the proposed revised formula relies on long-term A rated corporate bond yield spreads, whereas the revised OEB formula relies on long-term A rated utility bond yield spreads which are obtained from Bloomberg. The index selected by the OEB is a reasonable alternative to the A rate Corporate Bond Index proposed here.

[81] The Régie uses yields and spreads obtained from Bloomberg. Daily yields and spreads between the benchmark long-term and 10-year Canada bonds are also available at www.bankofcanada.ca.

[82] The index, the DEX Long Term Bond Index-Corporate A, formerly published by ScotiaCapital, is available by subscription from TSX Inc.

one of the first formulas adopted in Canada, remained unchanged between the issuance of RH-2-94 and its rescission in 2009[83], and the results of which were published each year since inception.

The resulting average indicated ROE for 1996-2009 under the revised formula is 10.7%, versus 9.6% under the RH-2-94 formula. To put this in perspective, the 10.7% average adjusted ROE compares to an average ROE adopted by regulators for U.S. gas distribution and electric utilities of 10.9% over the same period. The similarity in the average ROE produced by the adjusted formula and the average allowed ROEs for U.S. utilities is a reasonable outcome, given the similarity in the cost of capital environments in the two countries. As noted above, from 1998-2009, the average long-term Government of Canada and U.S. Treasury bond yields were within 10 basis points of each other (4.98% versus 5.07%). The average yield on long-term A rated corporate bonds in the two countries was identical (6.3% in both countries).[84]

Based on the proposed revised formula, the forecast long-term Canada bond yield of 4.7% and a long-term A rated corporate bond yield spread of 172 basis points[85], the 2011 multi-pipeline ROE would be 10.48%, compared to 8.82% under the RH-2-94 formula.

It is critical to recognize that the formula adopted has to be internally consistent with assumptions made setting the initial allowed ROE. It is perhaps obvious that it would not be reasonable to implement the proposed revised formula without resetting the allowed ROE at a level that explicitly recognizes that the ROEs that have been allowed since the Régie adopted its automatic adjustment mechanism reflect a much greater sensitivity to changes in long-term Canada bond yields than the empirical evidence supports.

Given the unpredictability of capital markets, there is sufficient potential for any automatic adjustment mechanism based on relatively simplistic relationships among variables to produce

[83] The BCUC adopted an automatic adjustment formula in 1994, but changed the adjustment factor several times between 1994 and 2009, when it eliminated the automatic adjustment mechanism.
[84] Measured by the DEX Long Corporate A index and Moody's Long-term A Rated Corporate Bond Yields for Canada and the U.S. respectively.
[85] Average of month-ends December 2009 and January 2010.

ROEs that deviate from a fair return. Consequently, establishing a process for a review on a regular basis would be prudent. Establishing a process for review of the ROE and formula every five years would balance the objective of achieving regulatory efficiency with the obligation to establish a fair return.

Specifying that the ROE would be subject to review once every five years does not mean that the Régie would have to instigate a comprehensive proceeding, but that the Régie would seek comments from stakeholders on a regularly scheduled basis as to the need for a review.

In addition to the recommended process for review of the return on equity, a trigger mechanism can provide an additional safeguard to ensure that the fair return standard continues to be satisfied. As the proposed formula incorporates both changes in the forecast long-term Government of Canada bond yield and corporate bond yield spreads, I recommend that a trigger mechanism be expressed in terms of a range around the recalibrated initial ROE. While the determination of an appropriate range is largely a judgment, a range of plus or minus 200 basis points would be reasonable.

If the ROE calculated by reference to the proposed revised formula were to be more than 200 basis points above or below the initial recalibrated ROE adopted for Gazifère, the underlying economic and capital market conditions would have changed sufficiently from current and forecast conditions to justify a canvassing of stakeholders to determine whether a formal review of both the starting ROE and formula is warranted. A plus or minus 200 basis point range on the ROE with the proposed revised formula corresponds to a ceiling on the forecast long-term Canada bond yield of approximately 8.70%.

While the establishment of a trigger mechanism may mitigate the need to conduct a comprehensive review on a regularly scheduled basis, it does not eliminate the need to ascertain on a regular basis whether the automatic adjustment formula is continuing to produce ROEs that meet the fair return standard.

While both a specified schedule for review and a trigger mechanism would provide important safeguards, stakeholders should retain the right to seek earlier review should changes in economic and capital market conditions so warrant.

APPENDICES

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APPENDICES

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APPENDIX A

THE FAIR RETURN STANDARD

Three standards for a fair return have arisen from the legal precedents for establishing a fair return, the capital attraction, financial integrity and comparable returns, or comparable investment, standard. The principal Court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923)*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

In *Northwestern*, Mr. Justice Lamont stated

> 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 *Bluefield*, the criteria for a fair return were described as follows:

> 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.

In *Hope*, Justice Douglas stated,

> By that standard the return on 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 fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction/financial integrity standards and the comparable returns standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, *Hope* opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination. The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment.

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. For regulated utilities historic costs have been substituted for marginal or incremental costs for two reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred.

The determination of the return on common equity for regulated companies has traditionally been a “hybrid” concept. The cost of equity is a forward-looking measure of the equity investors’ required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets.

The current cost of attracting capital is measured by reference to market values. The discounted cash flow test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors’ return requirements (in dollar terms).

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services; raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

Therefore, when the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value.

APPENDIX B

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F} \quad + \quad \boldsymbol{\beta}(\mathbf{R_M} - \mathbf{R_F}),$$

Where:

R_F = risk-free rate

β = covariability of the security with the market (M)

R_M = return on the market.

The model is based on restrictive assumptions, including:

a. Perfect, or efficient, markets exist where,

(1) each investor assumes he has no effect on security prices;

(2) there are no taxes or transaction costs;

(3) all assets are publicly traded and perfectly divisible;

(4) there are no constraints on short-sales; and,

(5) the same risk-free rate applies to both borrowing and lending.

b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

2. RISK-FREE RATE

a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

(1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government has been in a surplus position since 1997/1998 (eleven years), which reduced its financing requirements.[1] However, the demand for long-term government securities by institutions (e.g., pension funds) that match assets and liabilities has not declined. The pension funds, key purchasers of long-term government bonds, are typically buy and hold investors which means that the government bonds in their portfolios do not trade. Thus, there is the potential not only for a scarcity premium in prices due to the demand for long-term government bonds, but also potential illiquidity in the market.

(2) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to

[1] The Federal government is anticipating budget deficits for fiscal years 2009/10 to 2014/15.

be captured in the typical application of the CAPM which focuses on a long-term average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, and in the wake of the subprime mortgage crisis commencing in late 2007, investors have shifted to the safe haven of government securities, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM captures the lower government bond yields, but not the increase in the equity risk premium.

(3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The need to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

(4) The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

3. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance,* Boston: Irwin/McGraw Hill, 2006 (p. 151), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for estimation of the cost of equity is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which

mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.

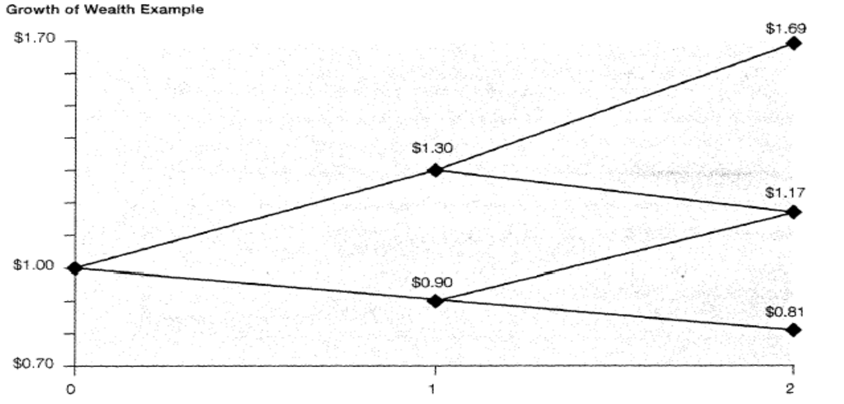
To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2008,* the following discussion was included:

To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.

Graph 5-4
Growth of Wealth Example



The most common outcome of \$1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)x(1-0.10)]^{½} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x \$1.69)	=	\$0.4225
+	(0.50 x \$1.17)	=	\$0.5850
+	(0.25 x \$0.81)	=	\$0.2025
	Total		\$1.2100

Therefore, \$1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of \$1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \text{ x } (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1 \text{ x } (1+0.0.082)^2 = \$1.17$$

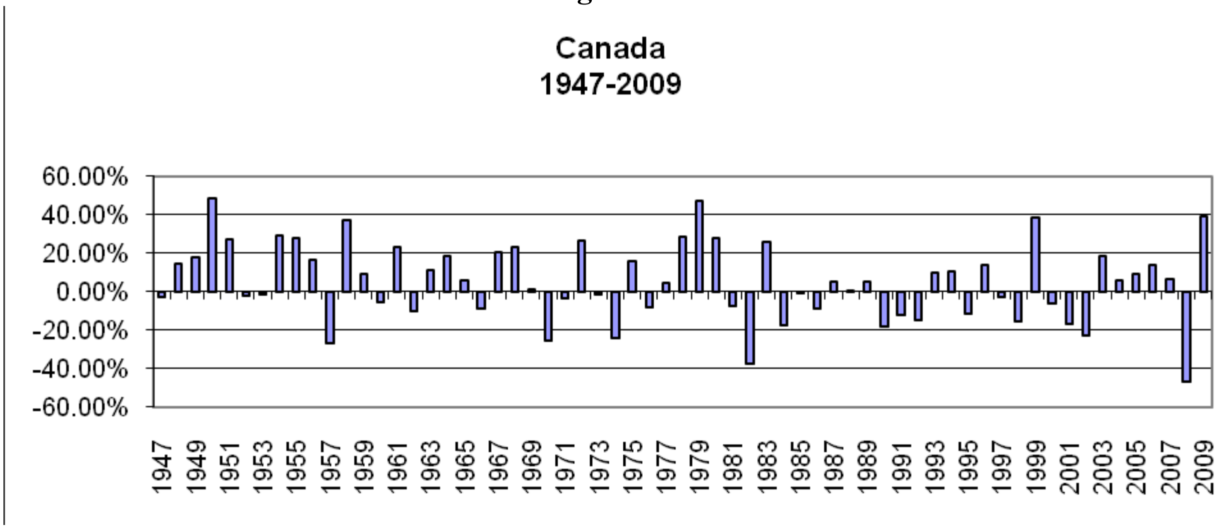
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historic annual risk premiums. The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[2]

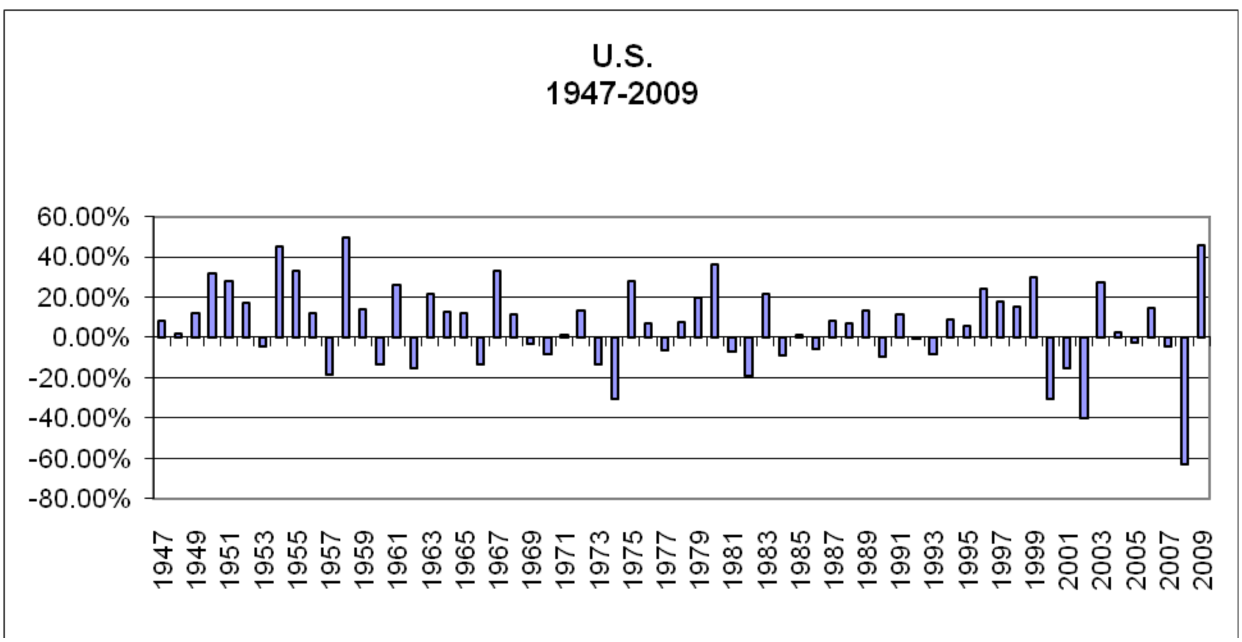
[2] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2009 is -0.02 for Canada and -0.12 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Figure B-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006*; Ibbotson, *Canadian Risk Premia Over Time 2008*, *TSX Review* and Bank of Canada

Figure B-2



Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2009 Yearbook*, www.standardandpoors.com and the Federal Reserve

4. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[3] The next largest sector, financial services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table B-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table B-1

	1980	2000
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2007, the energy and materials (largely mining) sectors accounted for close to 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 75% of the total market value of the composite. Despite the sharp decline in commodity prices in 2008-

[3] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

2009 and the fall-out of the sub-prime mortgage crisis, the same three sectors continued to represent just over three-quarters of the value of the S&P/TSX Composite Index at the end of 2009.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at December 2009 demonstrates the difference.

Table B-2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.3%	9.0%
Consumer Staples	2.8%	11.7%
Energy	27.6%	11.2%
Financials	30.5%	15.4%
Health Care	0.5%	13.4%
Industrials	5.6%	9.9%
Information Technology	3.5%	19.0%
Materials	19.4%	3.4%
Telecommunication Services	4.3%	3.1%
Utilities	1.7%	3.8%

Source: *TSX Review,* December 2009 and Standardandpoors.com.

Even within the remaining areas of the Canadian market (the approximately 25% accounted for by the non-resource and non-financial sectors); there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index as compared to the largest stock in the S&P 500 at that time (General Electric) which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the Composite regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some these concerns when they overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2009 there were 211 companies in the S&P/TSX Composite Index, including 44 income trusts.

The addition of income trusts in 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. At the end of 2009, income trusts continued to be a significant component of the S&P/TSX, accounting for approximately 21% of the issues and 7% of the value of the index.

Despite the change to the income tax treatment of income trusts announced in October 2006, income trusts significantly outperformed "conventional" equities during the period for which income trust market data are readily available. The annual compound total return for the S&P/TSX Capped Income Trust Index over the 1998-2009 period averaged 13.1%, compared to 6.9% for the S&P/TSX Composite Index. The exclusion of income trust returns from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[4] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension

[4] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.

Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[5] which supported the removal of the cap.[6] At that time, the *Globe and Mail* reported that the removal of the foreign content cap was expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[7] The Foreign Property Rule was finally eliminated in 2005.

5. FUTURE vs. HISTORIC RETURNS AND RISK PREMIUMS

a. Trends in Post World War II Canadian Equity and Government Bond Returns

Figures B-3 and B-4 compare historic Canadian stock returns, long-term government bond total and income[8] returns and equity risk premiums, over rolling 10-year periods ending 1956-2009.

[5] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

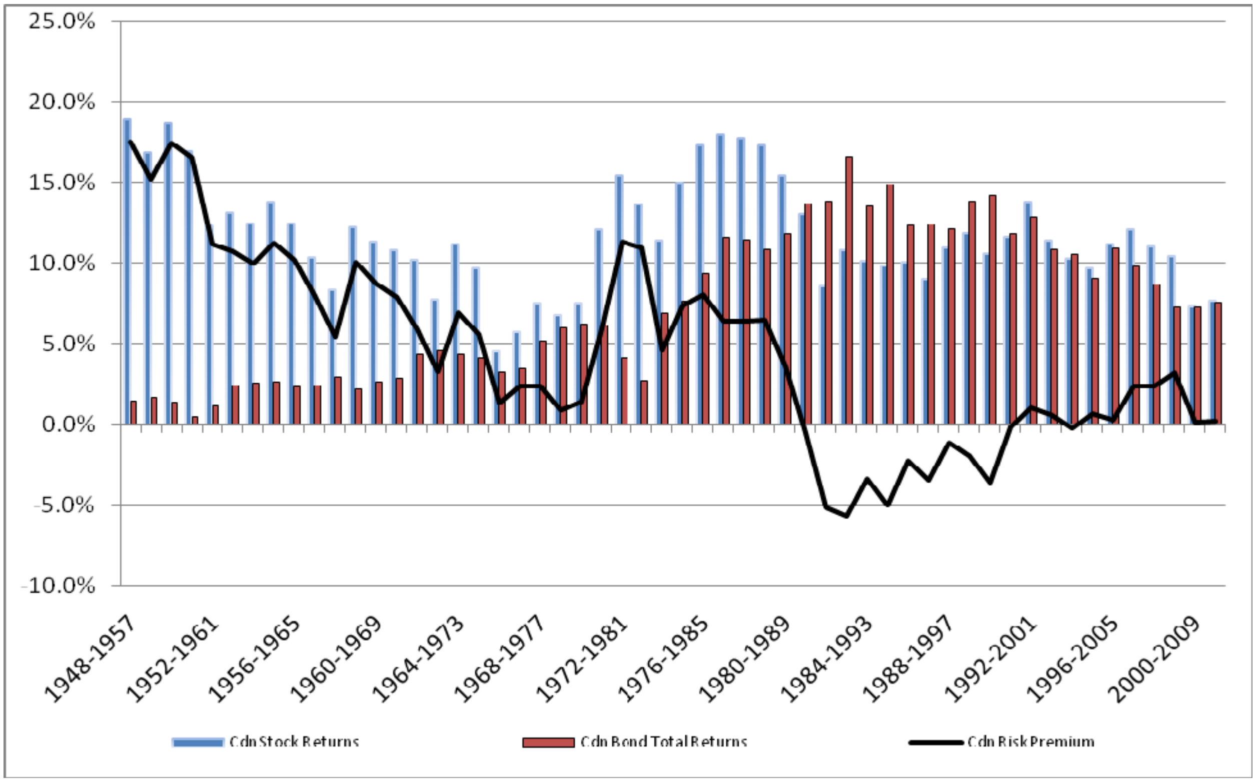
[6] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

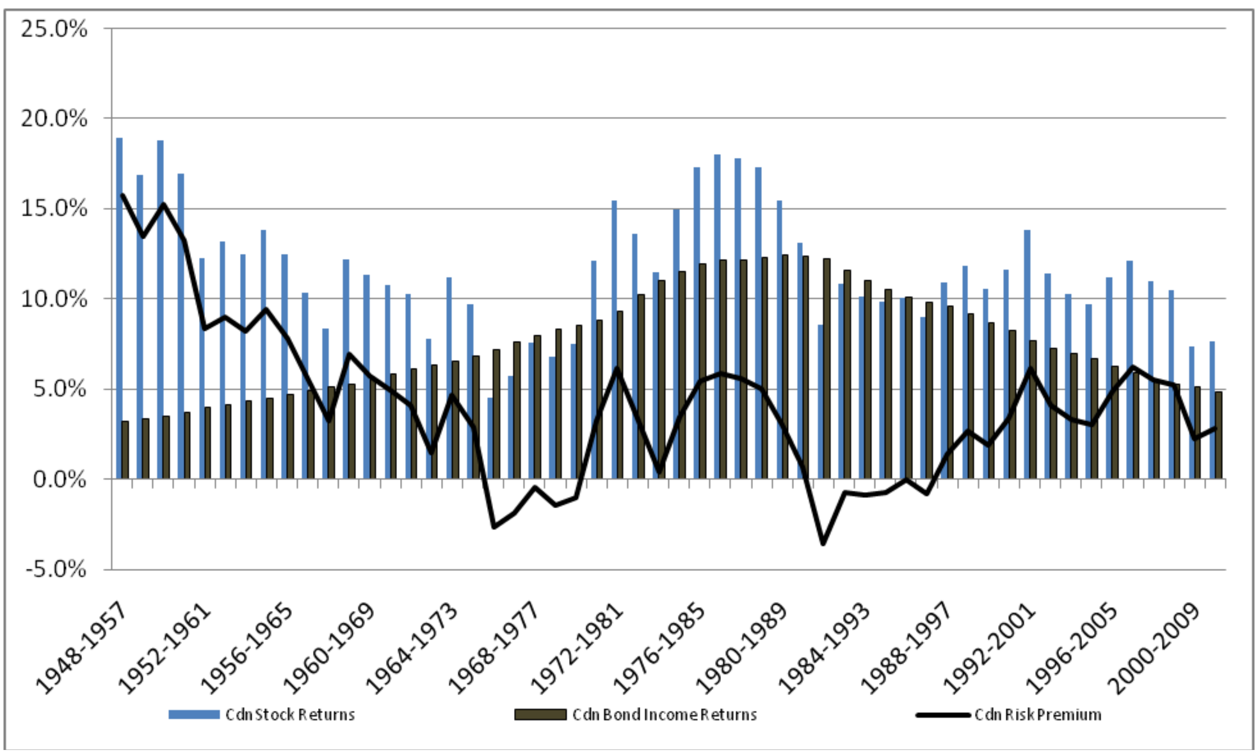
[7] Rob Carrick, *Finance: Your Bottom Line*, Globeandmail.com, February 23, 2005.

[8] The income return reflects only the bond coupon portion of the total bond return. The other components are the reinvestment return and the capital gain or loss. The bond coupon payment represents the riskless portion of the bond total return.

Figure B-3



. **Figure B-4**



Source for Figures B-3 and B-4: Schedule 7.

The rolling ten-year averages in both Figures B-3 and B-4 suggest that there has been no upward or downward trend over time in equity returns during the post World War II period. On average, equity market returns in Canada were 12.0% from 1947-2009. By comparison, bond returns (both Total and Income returns) exhibited an increase throughout much of the period, before beginning to decline in the early to mid-1990s. The pattern in the bond returns results from:

♦ rising bond yields in the 1950s through the mid-1980s, which produced capital losses on bonds and low bond total return;

♦ high bond income and income returns in the 1980s, reflecting the high rates of inflation; and,

♦ high bond total returns in the 1990s and first half of the 2000s, reflecting the decline in long-term government bond yields, resulting in capital gains and total returns well in excess of the yields.[9]

The resulting average income and total return on long-term government bonds in Canada has been approximately 7.0% during the post-World War II period (1947-2009), well in excess of the long-term Canada bond yields which are forecast to prevail going forward.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return, based solely on the post-World War II Canadian equity market returns, is approximately 12.0%. Based on a 2011 forecast long-term Canada bond yields of 4.7%, and an expected equity market return over the long-term of 12.0%, the indicated equity market risk premium is approximately 7.5%. Based on the longer-term (2011-2019) forecast for long-term

[9] The bond yield is, in fact, an estimate of the expected return.

Canada bond yields of approximately 5.25%,[10] the indicated equity market risk premium is 6.75%.

b. Comparison of Longer-Period Returns to Post-World War II Returns

A comparison of the longer-term equity market returns in Canada and the U.S. to the post-World War II returns demonstrates that the average nominal returns for the equity markets have not changed materially. Over the long-term, on average, the equity market return in both countries has been in the approximate range of 11.5%-12.0%, compared to the post World War II average returns of approximately 12.0-12.5%.

Table B-3

	Canada		U.S.	
	1924-2009	1947-2009	1926-2009	1947-2009
Equity Market Returns	11.6%	12.0%	11.8%	12.4%

Source: Schedule 6.

c. Trends in Price/Earnings Ratios

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[11] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[12] From 11.7 times in 1988, the P/E ratio gradually rose, peaking at over 46 times in late 2001. At the height of

[10] Consensus Economics, *Consensus Forecasts*, October 2009 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2011 to 2019. The average spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.
[11] Price to trailing earnings.
[12] The average from 1947-1988 was 13 times.

the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[13] By mid-2006, the P/E ratio had fallen to 17 times; at the end of 2009, with the sell-off in the market which commenced in mid-2007, it was 20 times (based on estimated 2009 operating earnings), compared to the long-term (1936-2009) average of approximately 16 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1936 (the first year for which P/E ratios are readily available) and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.3% from 1936-1988. The corresponding average return from 1936-2009 was 11.9%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1936-2009 period than over the 1936-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.4% over the entire 1947-2009 period. Stated differently, the increase in P/E ratios during the 1990s has not resulted in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable.

A review of equity returns in Canada indicates similar results. The 1936-1988 arithmetic average return for the Canadian equity market was 11.8%, higher than the average 1936-

[13] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

2009 return of 11.4%. Similarly, the 1947-1988 return of 12.9% is higher than the 1947-2009 return of 12.0%. There is no indication that rising P/E ratios during the bull market of the 1990s have resulted in average returns that are unsustainable going forward.

d. Impact of Inflation on Equity Market Returns

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking equity nominal (inclusive of inflation expectations) market return should differ from the historic nominal returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in both Canada and the U.S. has been higher than the expected rate of inflation. The arithmetic average CPI rate of inflation from 1926-2009 in Canada was 3.1%; the corresponding rate of inflation in the U.S. was also 3.1%. The most recent consensus long-term (2010-2019) forecast of CPI inflation for Canada is 2.0%; for the U.S., it is 2.2%.[14] The lower forecast rate of inflation compared to the historic rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically.

However an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table B-4 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

[14] Consensus Economics, *Consensus Forecasts*, October 2009.

Table B-4

Inflation Range	Canadian Nominal Equity Return	Canadian Average Rate of Inflation	Canadian Real Equity Return	U.S. Nominal Equity Return	U.S. Average Rate of Inflation	U.S. Real Equity Return
Less than 1%	15.9%	-1.3%	17.8%	13.0%	-2.0%	15.2%
1-3%	12.3%	1.9%	9.9%	18.2%	2.0%	15.9%
3-5%	4.8%	4.1%	0.6%	6.0%	3.7%	2.2%
Over 5%	12.5%	9.2%	3.4%	7.0%	8.2%	-1.1%
Avg. 1926-2009	11.4%	3.1%	8.2%	11.8%	3.1%	8.6%

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation.

e. Trends in Government Bond Returns and Expected Risk Premium

The analysis of stock and bond returns in Canada and the U.S. during the post World War II period reveals no upward or downward trend in market equity returns. Nevertheless, the achieved risk premiums have declined. The arithmetic average achieved risk premium in Canada (in relation to bond total returns) from 1947-1988 was 7.7%; in the U.S., it was 8.4%. By comparison, the corresponding 1947-2009 achieved risk premiums (in relation to the total returns on bonds) were 5.2% and 6.3% for Canada and the U.S. respectively. An analysis of the data shows that high bond returns have been the principal reason for the decline in experienced risk premiums, not a downward trend in equity returns. The average bond total return (income plus capital appreciation) in Canada from 1989-2009 was 10.0%.

Over the entire 1947-2009 period, the average return on long-term Canada bonds, both total and income returns, was approximately 7.0%. With long-term Canada bond yields currently at historically low levels (approximately 4.1% at the end of December 2009), and more likely to increase rather than decrease further, the 1947-2009 average bond returns of approximately 7.0% overstate the forward-looking expected bond return indicated by current and forecast 30-year Canada bond yields. A reasonable expected value of the long-term Canada bond return for the purpose of estimating the forward-looking equity market risk premium is the forecast of long-term Canada bond yields, rather than the historic average bond returns. The forecasts of the risk-free rate as proxied by the 30-year Government of Canada bond yield are in the range of 4.7% (2011 forecast of 30-year Canada bond yield) to 5.25% (forecast of 30-year Canada bond yield over the longer term).

f. Equity Market Risk Premium

Given the absence of any material upward or downward trend in the nominal historic equity market returns during the post World War II period, the longer-term equity market returns, the P/E ratio analysis, and the observed negative relationship between real returns and inflation, a reasonable expected value of the future equity market return is a range of 11.5%-12.0%[15], based on Canadian equity market returns and supported by U.S. equity market returns. The expected return on long-term Canada bonds, based on both the near-term (2011) and the longer-term forecasts of the 30-year Canada bond yield, is in the range of 4.7% to 5.25%. The resulting expected equity market risk premium is approximately 6.75%. Based on the analysis of the historic risk premiums in both Canada (primarily) and the U.S. and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.75%.

[15] Over the three-month period, October 2009-December 2009, the average dividend yield on the S&P/TSX was 2.8%. The expected long-term growth rate for the index based on available analysts' forecasts for the companies in the Composite, was 11.4%, indicating an expected return (based on a constant growth discounted cash flow approach) of approximately 14.5%.

6. RELATIVE RISK ADJUSTMENT

a. Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

(1) The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

(2) The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

(3) The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market)[16] are a good measure of the relative return requirement.

(4) Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

[16] The beta is equal to:

$$\frac{\text{Covariance }(R_E,R_M)}{\text{Variance }(R_M)}$$

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French stated in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect

> weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

Fama and French have developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM.[17]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and

[17] The additional factors are size and book to market.

expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[18]

b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table B-5

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 10, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table B-5 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of

[18] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2009, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,[19] and (c) the 10-year period ending 2009.

That analysis showed the following:

Table B-6

Returns Measured Over:	Coefficient on Beta	R^2
1988-2009	-.034	15%
1988-1997	-.017	1%
2000-2009	-.126	40%

Source: Schedule 10, page 2.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship. The results strongly suggest that, at a minimum, adjusted betas, rather than "raw" betas, should be relied upon in the application of the CAPM. Adjusting betas toward the equity market mean beta of 1.0 takes account of the empirically observed tendency of stocks with "raw" betas below 1.0 to achieve returns higher than implied by the theoretical single variable CAPM and vice versa.

[19] The use of this sub-period was intended to ensure elimination of the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.

APPENDIX C

DCF-BASED RISK PREMIUM TEST

1. SELECTION OF LOW RISK BENCHMARK U.S. DISTRIBUTION UTILITIES

For the estimation of the benchmark return, a sample of low risk U.S. distribution utilities was selected, comprised of all gas and electric distribution utilities satisfying the following criteria:

Gas Distribution Utility Criteria:

a. Classified by *Value Line* as a gas distributor;

b. Greater than 80% of assets in gas operations;

c. Consistent history of I/B/E/S analysts' forecasts;

d. Standard & Poor's and Moody's debt ratings of BBB+/Baa1 or higher;

e. Paid dividends in 2009.

Electric Distribution Utility Criteria:

a. Classified by *Value Line* as an electric utility;

b. Has more than 80% of its assets in electric or gas distribution operations, less than 5% of its total assets devoted to electricity generation and is not a pure electric transmission utility;

c. Consistent history of I/B/E/S analysts' forecasts;

d. Standard & Poor's and Moody's debt ratings of BBB+/Baa1 or higher;

e. Paid dividends in 2009.

The nine utilities that met these criteria are listed on Schedule 15.

2. CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the nine utilities in the sample from 1995-2009. The monthly DCF cost for each utility was estimated as the sum of the utilities' I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S mean earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 12). The monthly sample average ERPs were used to estimate the regression equations found on Schedule 12.

APPENDIX D

DISCOUNTED CASH FLOW TEST

1. DCF MODELS

a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[20]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

[20] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

The use of forecast GDP growth as the proxy for the expected long-term growth is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

Using the three-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

For Years 6 through 10, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 2 Growth)

Cash flows from Year 11 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

3. SELECTION OF PROXY BENCHMARK UTILITIES

The same sample of benchmark utilities was used as for the DCF-based risk premium test. The selection criteria for the low risk distribution utilities are described in Appendix C.

4. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk gas and electric distribution utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of January 26, 2010 as D_o; and,

(2) the average of the monthly high and low prices for the period November 1, 2009 to January 26, 2010 as P_o.

The constant growth model was applied using two estimates of long-term growth, the consensus of investment analysts' long-term earnings growth forecasts compiled by I/B/E/S and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the December 2009 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield.

The sustainable growth rate was derived from *Value Line* forecasts. Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (b) expected to be retained multiplied by expected return on equity (r). The external growth rate is estimated by the forecast growth in common stock outstanding (s) multiplied by the fraction of the investment expected to be retained (v). The sustainable growth rate is then calculated as the sum of br and sv. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.

Table D-1 below summarizes the results of the application of the constant growth model.

Table D-1

Growth Forecast	DCF Cost of Equity	
	Mean	**Median**
I/B/E/S Analysts' Forecasts	10.6%	10.0%
Sustainable Growth (*Value Line*)	10.1%	9.9%

Source: Schedules 16 and 17.

b. Three-Stage Model

The three-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), the average of the I/B/E/S and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). The long-run (2011-2020) expected nominal rate of growth in GDP is 5.0% based on the consensus of economists' forecasts (published twice annually) found in Blue Chip *Financial Forecasts*, December 1, 2009.

The three-stage DCF model estimates of the cost of equity for the benchmark low risk U.S. distribution utility sample (Schedule 18) are as follows:

Mean	9.8%
Median	9.7%

c. Results of the Constant Growth and Three-Stage Models

The results of the two models indicate a required "bare-bones" return on equity of approximately 9.75% (three-stage model) to 10.2% (constant growth model).

APPENDIX E

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[21]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial

[21] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[22]

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000 and took out a mortgage for the full amount. My home is currently worth $250,000 and my mortgage is now $85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $165,000 (market value of $250,000 less the $85,000 unpaid mortgage), not the "book value" of the equity in my home of $15,000, which reflects the original purchase price less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the

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[22] The financing flexibility allowance is estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x "bare-bones" Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a retention rate of 35% and a cost of equity of 10.0%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \times 10.0\%}{1 + [.35\,(1.075 - 1.0)]}$$

$$\text{ROE} = 10.5\%$$

The difference of 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

The cost of equity has been estimated using samples of comparable proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Two approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity. The first approach is based on the theory that the overall cost of capital does not change materially over a relatively broad range of capital structures. The second approach is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense.[23]

Schedules 20 and 21 provide the formulas and inputs for estimating the change in the cost of equity under each of the two approaches. Full recognition of the difference in financial risk between the market value capital structures of the publicly-traded Canadian utilities and the low risk U.S. distribution utilities and the typical book value capital structure of Canadian regulated utilities and the U.S. distribution utilities (40% and 48% equity respectively; see Schedules 4 and 5) results in an increase in the cost of equity of approximately 115 basis points.

[23] The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

APPENDIX F

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Electricity Distributors Association	2009
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007, 2009
Enbridge Pipelines (Southern Lights)	2007

FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000, 2008
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
MidAmerican Energy Company	2009
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007, 2009
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002

Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Nova Scotia Power	Calculation of ROE	2009
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

SCHEDULES

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

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TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Government Securities											
	T-Bills		10 Year		Long-Term		Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [4/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Year	Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]						
Annual												
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44	9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28	9.36	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01	1.33	8.64	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	1.22	7.59	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	1.12	8.30	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	0.88	7.89	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	0.63	7.75	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	0.53	7.60	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	0.79	7.04	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	1.20	7.62	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.02	1.31	8.24	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.25	1.48	7.73	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.22	1.55	7.35	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.78	1.46	6.54	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.28	1.17	6.14	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.53	1.16	5.62	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.47	1.21	6.06	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.61	1.31	6.06	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.41	2.37	6.54	0.94
2009	0.31	0.15	3.27	3.29	3.85	4.10	3.85	1.86	6.24	2.39	5.99	0.88

[1/] Rates on new issues.
[2/] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3/] Terms to maturity of l0 years or more.
[4/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: T-BILLS Canadian	T-BILLS U.S. [1/]	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. [2/]	Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [5/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	6.17	1.08	6.06	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.48	1.19	6.45	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.37	1.23	6.11	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	6.09	1.17	5.95	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.86	1.13	5.72	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.59	1.21	5.43	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.32	1.12	5.49	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.36	1.17	5.82	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.43	1.20	5.92	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.75	1.21	6.41	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.45	1.23	6.09	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.27	1.20	5.82	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.36	1.19	5.92	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.61	1.25	6.08	0.92
	q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.79	1.34	6.19	0.97
	q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.68	1.47	6.05	1.02
2008	q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.75	1.68	6.16	0.99
	q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.99	1.89	6.30	0.99
	q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.33	2.21	6.58	0.95
	q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.56	3.69	7.13	0.82
2009	q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.28	3.60	6.44	0.80
	q2	0.21	0.16	3.28	3.39	3.90	4.24	3.86	1.97	6.43	2.54	6.35	0.87
	q3	0.22	0.16	3.38	3.41	3.89	4.17	3.94	1.76	5.63	1.73	5.54	0.92
	q4	0.21	0.06	3.42	3.49	3.95	4.35	3.96	1.57	5.62	1.68	5.65	0.94
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.41	1.19	6.01	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.28	1.19	5.78	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.39	1.19	5.97	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.45	1.26	5.90	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.62	1.24	6.10	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.75	1.26	6.24	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07	5.78	1.33	6.18	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14	5.76	1.30	6.17	0.95
	Sep	3.96	3.82	4.34	4.59	4.44	4.83	4.44	2.07	5.83	1.39	6.22	1.01
	Oct	3.96	3.94	4.31	4.48	4.38	4.74	4.39	2.05	5.73	1.35	6.07	1.06
	Nov	3.91	3.15	3.98	3.97	4.16	4.40	4.15	2.07	5.69	1.53	6.00	1.00
	Dec	3.82	3.36	3.99	4.04	4.10	4.45	4.10	1.91	5.62	1.52	6.07	1.01
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.81	1.63	6.07	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.73	1.64	6.22	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.71	1.77	6.20	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.97	1.89	6.22	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.98	1.85	6.36	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	6.02	1.94	6.32	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	6.08	1.98	6.44	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.25	2.24	6.32	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.65	2.42	6.98	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.86	3.58	8.01	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.47	3.57	7.18	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.36	3.91	6.20	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.57	3.80	6.52	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.26	3.56	6.38	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	7.01	3.44	6.41	0.79
	Apr	0.20	0.14	3.09	3.16	3.84	4.05	3.74	2.05	6.84	3.00	6.55	0.84
	May	0.20	0.14	3.39	3.47	3.99	4.34	3.93	2.00	6.48	2.49	6.53	0.91
	Jun	0.24	0.19	3.36	3.53	3.86	4.32	3.91	1.86	5.98	2.12	5.96	0.86
	Jul	0.24	0.18	3.46	3.52	3.95	4.31	4.01	1.73	5.76	1.81	5.68	0.93
	Aug	0.20	0.15	3.37	3.40	3.89	4.18	3.94	1.81	5.57	1.68	5.54	0.91
	Sep	0.22	0.14	3.31	3.31	3.84	4.03	3.87	1.74	5.55	1.71	5.41	0.93
	Oct	0.22	0.05	3.42	3.41	3.92	4.23	3.95	1.60	5.59	1.67	5.55	0.93
	Nov	0.21	0.06	3.22	3.21	3.84	4.20	3.83	1.58	5.52	1.68	5.54	0.95
	Dec	0.19	0.06	3.61	3.85	4.08	4.63	4.09	1.53	5.76	1.68	5.86	0.96
2010	Jan	0.16	0.08	3.34	3.63	3.94	4.51	3.90	1.49	5.53	1.59	5.73	0.94

[1/] Rates on new issues.
[2/] 20-year constant maturities for 1974-1978; 30-year maturities, 1978-January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3/] Terms to maturity of l0 years or more.
[4/] Series discontinued June 2007.
[5/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000;
a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.
Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov
RBC Capital Markets, www.ustreas.gov

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Gazifère	**2/99; 12/09**	**Régie**	**D-99-09; D-2009-159**	**60.00**	**0.00**	**40.00**	**8.89**	**4.22**	
Gas Distributors									
AltaGas Utilities	11/09	EUB	2009-216	57.00	0.00	43.00	9.00	n/a	
ATCO Gas	11/09	EUB	2009-216	54.10	6.90	39.00	9.00	n/a	
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
Gaz Metropolitain	12/09	Régie	D-2009-156	54.00	7.50	38.50	9.20	4.30	
Pacific Northern Gas-West	5/07; 11/08	BCUC	G-55-07; L-55-08	56.20	3.80	40.00	9.12	4.35	1/
Terasen Gas	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	n/a	
Terasen Gas (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	n/a	
Terasen Gas(Whistler)	12/09	BCUC	G-35-09; G-158-09	60.00	0.00	40.00	10.00	n/a	
Union Gas	1/04; 5/06; 1/08	OEB	RP-2002-0158; EB-2006-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23	
Electric Utilities									
AltaLink	11/09	EUB	2009-216	64.00	0.00	36.00	9.00	n/a	
ATCO Electric									
Transmission	11/09	EUB	2009-216	58.00	6.00	36.00	9.00	n/a	
Distribution	11/09	EUB	2009-216	54.10	6.90	39.00	9.00	n/a	
EPCOR									
Transmission	11/09	EUB	2009-216	63.00	0.00	37.00	9.00	n/a	
Distribution	11/09	EUB	2009-216	59.00	0.00	41.00	9.00	n/a	
FortisAlberta Inc.	11/09	EUB	2009-216	59.00	0.00	41.00	9.00	n/a	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	n/a	
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16	
Maritime Electric	2/09	IRAC	UE-09-02	59.50	0.00	40.50	9.75	na	
Nova Scotia Power	3/06;11/08	NSUARB	2006 NSUARB 23; 2008 NSUARB 140	53.30	9.20	37.50	9.35	na	
Ontario Electricity Distributors	12/09	OEB	EB-2009-0084	60.00	0.00	40.00	9.75	4.25	
Ontario Power Generation	11/08	OEB	EB-2007-0905	53.00	0.00	47.00	8.65	4.75	
Gas Pipelines									
Foothills Pipe Lines (Yukon) Ltd.	12/05; 12/09	NEB	RH-2-94;TG-08-2005; NEB Letter 12-09	64.00	0.00	36.00	8.52	4.30	
TransCanada PipeLines	5/07; 12/09	NEB	RH-2-94;TG-06-2007; NEB Letter 12-09	60.00	0.00	40.00	8.52	4.30	
Trans Quebec & Maritimes Pipeline	3/09	NEB	RH-1-2008	60.00	0.00	40.00	9.70	n/a	2/
Westcoast Energy	12/06; 11/08	NEB	RH-2-94; TG-05-2006	64.00	0.00	36.00	8.57	4.36	3/

1/ ROE for first six months of 2009; PNG capital structure and ROE currently in proceeding before the BCUC.

2/ Capital structure and ROE not specified; ROE is the NEB's calculation at TQM's requested common equity ratio of 40%.

3/ Multi-pipeline ROE for 2009; 2010 ROE not yet determined.

Source: Regulatory Decisions.

**RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR CANADIAN UTILITIES**

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Gazifère	14.25	14.25	14.00	12.50	12.25	12.60	12.25	11.75	11.00	10.00	10.13	10.01	10.08	10.30	9.86	10.10	9.34	9.31	9.18	8.82
Gas Distributors																				
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	9.00
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76
Pacific Northern Gas [3/]	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12
Terasen Gas [3/]	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**8.96**	**8.59**	**8.77**	**8.71**
Electric Utilities																				
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	9.00
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[1/]	[1/]	[1/]	[1/]	[1/]	[1/]	9.40	9.60	9.50	8.93	8.51	8.75	9.00
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	9.00
FortisBC Inc. [3/]	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	na	9.35
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[1/]	[2/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	na	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.88**
Gas Pipelines (NEB)																				
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**	**8.57**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.02**	**8.66**	**8.78**	**8.77**

[1/] Negotiated settlement, details not available.
[2/] Negotiated settlement, implicit ROE made public is 10.5%.
[3/] Allowed ROEs for 2009 for first six months

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED RETURNS
FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities			U.S. Gas Utilities			U.S. Electric Utilities		
Year	Allowed ROE	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.62	4.07	12.67	8.62	4.05	12.70	8.62	4.08
1991	13.56	9.72	3.85	12.51	8.09	4.43	12.46	8.09	4.38	12.55	8.09	4.47
1992	12.94	8.68	4.26	12.06	7.68	4.39	12.01	7.68	4.34	12.09	7.68	4.42
1993	12.16	7.86	4.30	11.37	6.58	4.79	11.35	6.58	4.77	11.41	6.58	4.83
1994	11.50	8.69	2.81	11.34	7.41	3.93	11.35	7.41	3.94	11.34	7.41	3.93
1995	12.13	8.41	3.72	11.51	6.81	4.70	11.43	6.81	4.62	11.55	6.81	4.74
1996	11.36	7.75	3.62	11.29	6.72	4.57	11.19	6.72	4.47	11.39	6.72	4.67
1997	10.84	6.66	4.18	11.34	6.57	4.77	11.29	6.57	4.72	11.40	6.57	4.83
1998	10.15	5.59	4.56	11.59	5.53	6.06	11.51	5.53	5.98	11.66	5.53	6.13
1999	9.50	5.72	3.78	10.74	5.91	4.83	10.66	5.91	4.75	10.77	5.91	4.86
2000	9.79	5.71	4.08	11.41	5.88	5.53	11.39	5.88	5.51	11.43	5.88	5.55
2001	9.68	5.77	3.92	11.05	5.47	5.58	10.95	5.47	5.48	11.09	5.47	5.62
2002	9.62	5.67	3.95	11.10	5.41	5.69	11.03	5.41	5.62	11.16	5.41	5.75
2003	9.71	5.31	4.40	10.98	5.03	5.95	10.99	5.03	5.96	10.97	5.03	5.94
2004	9.59	5.11	4.48	10.66	5.09	5.56	10.59	5.09	5.50	10.73	5.09	5.64
2005	9.51	4.38	5.13	10.50	4.52	5.98	10.46	4.52	5.94	10.54	4.52	6.02
2006	9.02	4.26	4.76	10.39	4.87	5.52	10.44	4.87	5.57	10.36	4.87	5.49
2007	8.66	4.30	4.37	10.30	4.80	5.51	10.24	4.80	5.44	10.36	4.80	5.56
2008	8.78	4.04	4.74	10.42	4.22	6.20	10.37	4.22	6.15	10.46	4.22	6.24
2009	8.77	3.85	4.92	10.36	4.10	6.27	10.19	4.10	6.10	10.48	4.10	6.39
Means:												
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**7.74**	**4.38**	**12.19**	**7.74**	**4.45**
1994-1997	**11.46**	**7.88**	**3.58**	**11.37**	**6.88**	**4.49**	**11.32**	**6.88**	**4.44**	**11.42**	**6.88**	**4.54**
1998-2009	**9.40**	**4.98**	**4.42**	**10.79**	**5.07**	**5.72**	**10.74**	**5.07**	**5.67**	**10.83**	**5.16**	**5.71**

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; various Canadian regulatory decisions; Bank of Canada; Federal Reserve; U.S. Treasury.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

		Bond Rating			CBS
Company	**Debt Rated**	**DBRS**	**Moody's**	**S&P**	**Stock Ranking**
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A-	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [1/]	Average
Terasen Gas	Senior Secured	A	A1	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures	A(low)		BBB+	
EPCOR Utilities Inc	Senior Unsecured	A(low)		BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	A-	Very conservative
FortisBC Inc	Secured Debentures (DBRS)	BBB(high)	Baa2		Very conservative
	Senior Unsecured (Moody's)				
Hamilton Utilities	Senior Unsecured			A+	
Hydro One	Senior Unsecured	A(high)	Aa3	A+	
Hydro Ottawa Holding Inc.	Senior Unsecured	A		A	
London Hydro	Issuer			A	
Maritime Electric	Senior Secured			BBB+	Very conservative
Newfoundland Power	Senior Secured	A	A2	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB+	Very conservative
Toronto Hydro	Senior Unsecured	A(high)		A	
Veridian Corp.	Issuer	A			
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A3	A-	Very conservative
Trans Quebec & Maritimes	Senior Unsecured	A(low)		BBB+	
TransCanada PipeLines	Senior Unsecured	A	A3	A-	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Gas Distributors		**A**	**A3**	**A-**	**Very conservative**
All Companies		**A**	**A3**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2008)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Gas Distributors [4/]				
Enbridge Gas Distribution	48.7%	8.1%	2.2%	41.1%
Gaz Metropolitain	62.3%	1.2%	0.0%	36.5%
Pacific Northern Gas	46.1%	0.4%	3.0%	50.4%
Terasen Gas	59.0%	5.2%	0.0%	35.8%
Union Gas	58.6%	2.0%	0.0%	39.4%
Electric Utilities				
AltaLink L.P.	61.7%	0.0%	0.0%	38.3%
CU Inc.	56.6%	0.0%	5.2%	38.3%
Enersource	56.2%	0.0%	0.0%	43.8%
ENMAX Corp.	37.3%	4.6%	0.0%	58.1%
EPCOR Utilities Inc.	50.3%	2.6%	2.3%	44.8%
FortisAlberta Inc.	60.0%	0.5%	0.0%	39.4%
FortisBC Inc.	59.1%	0.0%	0.0%	40.9%
Hamilton Utilities	36.3%	0.0%	0.0%	63.7%
Hydro One Inc.	54.5%	0.0%	2.9%	42.6%
Hydro Ottawa Holding Inc.	44.1%	0.0%	0.0%	55.9%
London Hydro	36.1%	0.0%	0.0%	63.9%
Maritime Electric	53.6%	6.2%	0.0%	40.2%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%
Nova Scotia Power	54.3%	0.8%	4.7%	40.1%
Toronto Hydro	55.2%	0.0%	0.0%	44.8%
Veridian	39.2%	0.0%	0.0%	60.8%
Pipelines				
Enbridge Pipelines Inc.	52.7%	7.0%	0.0%	40.4%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%
Trans Quebec & Maritimes	69.9%	0.0%	0.0%	30.1%
TransCanada PipeLines Ltd.	54.1%	5.0%	1.2%	39.7%
Westcoast Energy Inc.	52.6%	1.2%	4.9%	41.3%
Medians				
Gas Distributors	**58.6%**	**2.0%**	**0.0%**	**39.4%**
All Companies	**54.2%**	**0.5%**	**0.0%**	**41.0%**

1/ Includes current portion of long-term debt and preferred securities classified as debt.
2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.
3/ Includes minority interest in common shares of subsidiary companies.
4/ The average of the four quarters ending September 2009 was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.

Source: Reports to Shareholders

TRAILING FOUR QUARTERS CAPITAL STRUCTURE BASED ON TOTAL CAPITAL FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES

Company	Long Term Debt %	Short Term Debt %	Preferred %	Common Equity %
AGL RESOURCES INC	44.3	12.5	0.0	43.2
CONSOLIDATED EDISON	49.7	1.5	1.0	47.8
NEW JERSEY RESOURCES	36.0	8.4	0.0	55.6
NICOR INC	25.3	22.8	0.0	51.9
NORTHWEST NATURAL GAS CO	43.0	9.1	0.0	47.9
NSTAR	49.0	12.2	0.9	37.9
PIEDMONT NATURAL GAS CO	38.9	16.8	0.0	44.3
SOUTH JERSEY INDUSTRIES INC	41.1	13.9	0.0	45.0
WGL HOLDINGS INC	34.8	7.6	1.4	56.2
Mean	40.2	11.6	0.4	47.8
Median	41.1	12.2	0.0	47.8

Trailing four quarters ending calendar year 3rd quarter 2009.

Source: Company Annual Reports to Shareholders and 10-Ks.

HISTORIC EQUITY MARKET RISK PREMIUMS

(ARITHMETIC AVERAGES)

Canada
(1947-2009)

Stock Return	Bond Total Return	Risk Premium
12.0	6.8	5.2

Stock Return	Bond Income Return	Risk Premium
12.0	7.1	4.9

United States
(1947-2009)

Stock Return	Bond Total Return	Risk Premium
12.4	6.1	6.3

Stock Return	Bond Income Return	Risk Premium
12.4	6.0	6.4

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review
www.federalreserve.gov, www.bankofcanada.gov

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

(1924-2009)

Stock Return	Bond Total Return	Risk Premium
11.6	6.4	5.2

Stock Return	Bond Income Return	Risk Premium
11.6	6.3	5.3

(1926-2009)

Stock Return	Bond Total Return	Risk Premium
11.8	5.7	6.1

Stock Return	Bond Income Return	Risk Premium
11.8	5.2	6.6

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review
www.federalreserve.gov

10-YEAR ROLLING AVERAGE CANADIAN MARKET RETURNS

	Canadian Stock Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1947-1956	18.94%	1.40%	17.53%	3.21%	15.72%
1948-1957	16.84%	1.68%	15.17%	3.37%	13.47%
1949-1958	18.76%	1.35%	17.41%	3.50%	15.26%
1950-1959	16.95%	0.42%	16.54%	3.72%	13.23%
1951-1960	12.29%	1.14%	11.15%	3.96%	8.32%
1952-1961	13.16%	2.43%	10.73%	4.15%	9.01%
1953-1962	12.49%	2.54%	9.96%	4.31%	8.18%
1954-1963	13.84%	2.60%	11.24%	4.46%	9.38%
1955-1964	12.48%	2.30%	10.18%	4.67%	7.81%
1956-1965	10.36%	2.43%	7.94%	4.88%	5.48%
1957-1966	8.33%	2.94%	5.39%	5.10%	3.24%
1958-1967	12.20%	2.14%	10.07%	5.29%	6.91%
1959-1968	11.32%	2.62%	8.70%	5.57%	5.76%
1960-1969	10.78%	2.87%	7.92%	5.83%	4.95%
1961-1970	10.25%	4.35%	5.89%	6.12%	4.13%
1962-1971	7.77%	4.53%	3.24%	6.32%	1.45%
1963-1972	11.22%	4.34%	6.88%	6.55%	4.67%
1964-1973	9.69%	4.08%	5.60%	6.81%	2.88%
1965-1974	4.55%	3.22%	1.33%	7.20%	-2.65%
1966-1975	5.73%	3.40%	2.33%	7.61%	-1.88%
1967-1976	7.54%	5.15%	2.39%	7.99%	-0.45%
1968-1977	6.80%	5.97%	0.84%	8.28%	-1.48%
1969-1978	7.53%	6.18%	1.35%	8.55%	-1.03%
1970-1979	12.09%	6.11%	5.97%	8.84%	3.25%
1971-1980	15.46%	4.12%	11.33%	9.34%	6.12%
1972-1981	13.63%	2.67%	10.97%	10.26%	3.37%
1973-1982	11.45%	6.85%	4.59%	11.03%	0.42%
1974-1983	14.97%	7.64%	7.33%	11.49%	3.48%
1975-1984	17.32%	9.32%	8.00%	11.92%	5.40%
1976-1985	17.98%	11.56%	6.42%	12.14%	5.84%
1977-1986	17.77%	11.42%	6.36%	12.18%	5.60%
1978-1987	17.29%	10.86%	6.43%	12.31%	4.98%
1979-1988	15.43%	11.78%	3.65%	12.41%	3.01%
1980-1989	13.09%	13.67%	-0.58%	12.38%	0.71%
1981-1990	8.59%	13.80%	-5.20%	12.20%	-3.61%
1982-1991	10.82%	16.54%	-5.72%	11.59%	-0.77%
1983-1992	10.12%	13.55%	-3.43%	10.98%	-0.85%
1984-1993	9.83%	14.88%	-5.05%	10.55%	-0.72%
1985-1994	10.05%	12.33%	-2.27%	10.09%	-0.04%
1986-1995	9.00%	12.43%	-3.43%	9.79%	-0.79%
1987-1996	10.94%	12.10%	-1.17%	9.57%	1.36%
1988-1997	11.85%	13.80%	-1.96%	9.19%	2.65%
1989-1998	10.58%	14.17%	-3.59%	8.68%	1.90%
1990-1999	11.61%	11.83%	-0.21%	8.23%	3.38%
1991-2000	13.83%	12.86%	0.98%	7.69%	6.14%
1992-2001	11.38%	10.81%	0.57%	7.27%	4.11%
1993-2002	10.28%	10.51%	-0.23%	6.93%	3.34%
1994-2003	9.69%	9.03%	0.67%	6.65%	3.04%
1995-2004	11.16%	10.92%	0.24%	6.26%	4.90%
1996-2005	12.12%	9.79%	2.32%	5.86%	6.25%
1997-2006	11.01%	8.69%	2.32%	5.50%	5.51%
1998-2007	10.47%	7.27%	3.20%	5.24%	5.23%
1999-2008	7.33%	7.22%	0.12%	5.09%	2.24%
2000-2009	7.67%	7.51%	0.16%	4.85%	2.81%

Source: Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; TSX Review

10-YEAR ROLLING AVERAGE U.S. MARKET RETURNS

	US Stock Returns	US Bond Total Returns	US Risk Premium Bond Total Returns	US Bond Income Returns	US Risk Premium Bond Income Returns
1947-1956	19.38%	0.85%	18.54%	2.53%	16.85%
1948-1957	17.74%	1.86%	15.88%	2.66%	15.07%
1949-1958	21.52%	0.91%	20.62%	2.75%	18.77%
1950-1959	20.84%	0.04%	20.80%	2.93%	17.91%
1951-1960	17.71%	1.41%	16.31%	3.14%	14.58%
1952-1961	18.00%	1.90%	16.10%	3.28%	14.72%
1953-1962	15.29%	2.47%	12.82%	3.42%	11.87%
1954-1963	17.67%	2.23%	15.44%	3.52%	14.15%
1955-1964	14.06%	1.86%	12.20%	3.66%	10.40%
1956-1965	12.15%	2.06%	10.09%	3.80%	8.34%
1957-1966	10.48%	2.98%	7.50%	3.95%	6.53%
1958-1967	13.96%	1.32%	12.64%	4.07%	9.89%
1959-1968	10.73%	1.90%	8.83%	4.29%	6.44%
1960-1969	8.68%	1.62%	7.06%	4.49%	4.20%
1961-1970	9.04%	1.45%	7.58%	4.73%	4.30%
1962-1971	7.78%	2.68%	5.10%	4.98%	2.80%
1963-1972	10.55%	2.56%	7.99%	5.17%	5.38%
1964-1973	6.80%	2.33%	4.48%	5.43%	1.37%
1965-1974	2.51%	2.41%	0.10%	5.74%	-3.23%
1966-1975	4.98%	3.26%	1.72%	6.12%	-1.14%
1967-1976	8.37%	4.57%	3.80%	6.46%	1.91%
1968-1977	5.26%	5.42%	-0.16%	6.72%	-1.46%
1969-1978	4.81%	5.33%	-0.52%	6.96%	-2.15%
1970-1979	7.50%	5.71%	1.79%	7.25%	0.25%
1971-1980	10.34%	4.11%	6.24%	7.57%	2.77%
1972-1981	8.42%	2.97%	5.45%	8.10%	0.33%
1973-1982	8.67%	6.44%	2.23%	8.86%	-0.19%
1974-1983	12.38%	6.61%	5.77%	9.25%	3.14%
1975-1984	15.66%	7.73%	7.93%	9.69%	5.96%
1976-1985	15.15%	9.90%	5.25%	10.02%	5.13%
1977-1986	14.61%	10.68%	3.93%	10.13%	4.49%
1978-1987	15.86%	10.48%	5.38%	10.21%	5.65%
1979-1988	16.88%	11.56%	5.32%	10.31%	6.57%
1980-1989	18.19%	13.50%	4.69%	10.31%	7.88%
1981-1990	14.63%	14.51%	0.12%	10.13%	4.50%
1982-1991	18.17%	16.25%	1.92%	9.80%	8.38%
1983-1992	16.80%	13.02%	3.78%	9.17%	7.63%
1984-1993	15.55%	14.78%	0.76%	8.85%	6.70%
1985-1994	15.05%	12.46%	2.59%	8.34%	6.71%
1986-1995	15.58%	12.53%	3.05%	7.97%	7.61%
1987-1996	16.04%	9.98%	6.06%	7.69%	8.35%
1988-1997	18.85%	11.84%	7.01%	7.56%	11.29%
1989-1998	20.03%	12.18%	7.85%	7.25%	12.78%
1990-1999	18.98%	9.47%	9.51%	6.93%	12.06%
1991-2000	18.39%	11.00%	7.39%	6.76%	11.63%
1992-2001	14.15%	9.44%	4.71%	6.49%	7.66%
1993-2002	11.17%	10.42%	0.75%	6.32%	4.85%
1994-2003	13.04%	8.74%	4.30%	6.08%	6.96%
1995-2004	14.00%	10.37%	3.63%	5.93%	8.07%
1996-2005	10.74%	7.98%	2.76%	5.64%	5.11%
1997-2006	10.02%	8.19%	1.82%	5.49%	4.53%
1998-2007	7.23%	7.60%	-0.37%	5.31%	1.92%
1999-2008	0.67%	8.88%	-8.21%	5.17%	-4.50%
2000-2009	0.91%	7.51%	-6.60%	5.02%	-4.11%

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook,
www.federalreserve.gov, www.standardandpoors.com

Schedule 8

FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE

Five Year Periods Ending:	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**2.86**	**4.35**	**4.88**	**4.55**
10 Sector Indices														
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.07	4.47
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.36	3.89
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	7.37	6.69
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	5.38	4.83
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	5.38	7.48
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.48	5.57
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	11.68	12.98
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	8.48	6.70
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	5.07	6.09
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.32	4.05
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.06**	**6.27**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.38**	**5.71**

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:														
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.74**	**0.71**	**0.71**	**0.65**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.80**	**0.71**

Source: TSX Review

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49
2009	0.56	0.28	1.35	0.80	0.41	0.83	1.22	1.24	0.47	0.41

Source: TSX Review

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS

	Compound Returns						Betas					
	56-03	**56-97**	**64-73**	**74-83**	**84-93**	**94-03**	**56-03**	**56-97**	**64-73**	**74-83**	**84-93**	**94-03**
Metals/Minerals	0.08	0.08	0.07	0.11	0.07	0.07	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	0.10	0.10	0.16	0.16	0.11	-0.03	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	0.10	0.08	0.15	0.12	0.05	0.15	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	0.07	0.07	0.05	0.12	0.10	0.03	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	0.11	0.12	0.10	0.14	0.11	0.10	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	0.07	0.10	0.08	0.11	0.06	0.01	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [1/]	0.05	0.05	0.01	0.17	-0.02	0.01	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	0.10	0.11	0.13	0.18	0.03	0.09	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	0.12	0.12	0.05	0.14	0.14	0.13	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	0.11	0.11	0.03	0.18	0.11	0.16	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	0.13	0.15	0.19	0.15	0.13	0.07	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	0.10	0.11	0.11	0.12	0.09	0.07	0.78	0.86	0.93	0.84	0.83	0.46
Finance	0.12	0.13	0.12	0.12	0.12	0.18	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	0.11	0.11	0.13	0.15	0.09	0.14	0.94	1.03	1.26	0.97	1.20	0.68
Intercept							**0.18**	**0.18**	**0.12**	**0.15**	**0.14**	**0.12**
Adjusted R Square							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Data only available starting July 1961

Source: TSX Review

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS

	Compound Returns [1/]			Betas		
	88-09	88-97	00-09	88-09	88-97	00-09
Consumer Discretionary	0.062	0.102	0.018	0.738	0.904	0.672
Consumer Staples	0.114	0.127	0.094	0.341	0.727	0.121
Energy	0.111	0.084	0.176	0.793	0.765	0.789
Financials	0.132	0.183	0.121	0.802	1.039	0.597
Health Care	0.029	0.155	-0.088	0.758	0.807	0.616
Industrials	0.059	0.083	0.054	0.941	1.131	0.930
Information Technology	0.065	0.218	-0.157	1.706	1.213	2.015
Materials	0.069	0.034	0.120	0.971	1.257	0.856
Telecommunication Services	0.121	0.154	0.024	0.691	0.578	0.515
Utilities	0.102	0.115	0.143	0.288	0.624	0.149
Intercept				**0.11**	**0.14**	**0.14**
Adjusted R Square				**15%**	**1%**	**40%**
Beta				**-0.034**	**-0.017**	**-0.126**

[1/] Data only available starting December 1987

Source: TSX Review

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 [3/]
Canadian Utilities	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.06	0.38
Emera	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.16	0.39
Enbridge	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.30	0.51
Fortis	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.20	0.48
PNG	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54	0.35	0.26	0.44	0.24
Terasen Inc [1/]	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na	na	na	na	na
TransCanada Pipelines	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.39	0.44
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**	**0.48**	**0.25**	**0.26**	**0.41**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**	**0.53**	**0.24**	**0.25**	**0.42**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.41	0.56

Adjusted Betas [2/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 [3/]
Canadian Utilities	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.37	0.59
Emera	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.44	0.59
Enbridge	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.53	0.67
Fortis	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.46	0.65
PNG	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69	0.56	0.50	0.62	0.49
Terasen Inc	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na	na	na	na	na
TransCanada Pipelines	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.59	0.63
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**	**0.65**	**0.50**	**0.50**	**0.60**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**	**0.68**	**0.49**	**0.50**	**0.61**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.60	0.71

[1/] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.
[2/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.
[3/] Three-year beta based on weekly data calculated through January 2010

Source: Standard and Poor's Research Insight and TSX Review.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR
BENCHMARK U.S. DISTRIBUTION UTILITIES
(Annual Averages of Monthly Data)

	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Risk Premium	Moody's Spread
1995	6.3	4.2	10.6	6.8	3.7	1.1
1996	6.0	4.2	10.2	6.7	3.4	1.0
1997	5.5	4.4	10.0	6.6	3.4	1.0
1998	4.8	4.8	9.5	5.5	4.0	1.5
1999	5.1	4.8	9.9	5.9	4.0	1.7
2000	5.5	5.1	10.6	5.9	4.7	2.4
2001	5.1	5.6	10.7	5.5	5.2	2.3
2002	5.0	5.5	10.4	5.4	5.0	1.9
2003	4.9	4.9	9.8	5.0	4.8	1.5
2004	4.5	4.3	8.7	5.1	3.6	1.0
2005	4.1	4.4	8.4	4.5	3.9	1.1
2006	4.1	4.6	8.7	4.9	3.8	1.2
2007	3.9	4.8	8.7	4.8	3.9	1.3
2008	4.3	5.1	9.5	4.2	5.2	2.3
2009	4.8	5.4	10.1	4.1	6.1	1.9
Means for Long Treasury Yields:						
Under 5.0	**4.4**	**4.8**	**9.2**	**4.5**	**4.7**	**1.6**
5.0-5.99	**4.9**	**5.0**	**9.9**	**5.5**	**4.4**	**1.7**
6.0-6.99	**5.7**	**4.4**	**10.2**	**6.5**	**3.7**	**1.3**
7.0 and above	**6.4**	**4.3**	**10.6**	**7.3**	**3.3**	**0.9**
Means:						
1995 - 2009	**4.9**	**4.8**	**9.7**	**5.4**	**4.3**	**1.5**
1999 - 2009	**4.6**	**4.9**	**9.6**	**5.0**	**4.6**	**1.7**

[1/] Dividend Yield is adjusted for I/B/E/S/ growth
Source: Standard & Poor's Research Insight, I/B/E/S and www.federalreserve.gov

DCF-BASED EQUITY RISK PREMIUM STUDY FOR
BENCHMARK U.S. DISTRIBUTION UTILITIES

Regression Analysis Results 1995-2009

Equation 1:

Equity Risk Premium = 7.30 - 0.55 (30-Year Treasury Yield)

t-statistics:

Long-term Bond Yield = -9.62

R^2 = 34%

Equity Risk Premium at Long-Term Bond Yield of 4.70% = 4.7%

ROE at Long-Term Bond Yield of 4.70% = 9.4%

Equation 2:

Equity Risk Premium = 4.75 - 0.34 (30-Year Treasury Yield) + 0.92 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

Long-term Bond Yield = -7.93
Utility/government bond yield spread = 13.64

R^2 = 68%

Equity Risk Premium at Long-term Bond Yield of 4.70% and Spread of 1.60% = 4.6%

ROE at Long-Term Bond Yield of 4.70% and = 9.3%

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK U.S. DISTRIBUTION UTILITIES

Regression Analysis Results 1999-2009

Equation 1:

Equity Risk Premium = 6.93 - 0.47 (30-Year Treasury Yield)

t-statistics:
Long-term Bond Yield = -4.54
R^2 = 14%

Equity Risk Premium at Long-Term Bond Yield of 4.70% = 4.7

ROE at Long-Term Bond Yield of 4.70% = 9.4%

Equation 2:

Equity Risk Premium = 5.28 - 0.47 (30-Year Treasury Yield) + 0.98 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
Long-term Bond Yield = -6.77
Utility/government bond yield spread = 12.65

R^2 = 61%

Equity Risk Premium at Long-term Bond Yield of 4.70% and Spread of 1.60% = 4.6

ROE at Long-Term Bond Yield of 4.70% and = 9.3%

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1956-2009)

Utilities Index Return	Bond Total Return	Risk Premium
12.1	7.6	4.5

Utilities Index Return	Bond Income Return	Risk Premium
12.1	7.8	4.3

United States
(1947-2009)

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.9	6.1	5.8

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.9	6.0	5.9

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
10.9	6.1	4.8

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
10.9	6.0	4.9

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2009.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2009 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2009 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review
Mergent Corporate News Reports, www.federal reserve.com,
S&P Research Insight

**10-YEAR ROLLING AVERAGE RETURNS
FOR CANADIAN UTILITIES AND GOVERNMENT BONDS**

	S&P/TSX Utilities Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1956-1965	14.3%	2.4%	11.9%	4.9%	9.4%
1957-1966	10.1%	2.9%	7.1%	5.1%	5.0%
1958-1967	11.3%	2.1%	9.2%	5.3%	6.0%
1959-1968	10.8%	2.6%	8.2%	5.6%	5.2%
1960-1969	7.9%	2.9%	5.0%	5.8%	2.1%
1961-1970	7.2%	4.4%	2.8%	6.1%	1.0%
1962-1971	6.9%	4.5%	2.4%	6.3%	0.6%
1963-1972	9.2%	4.3%	4.9%	6.5%	2.7%
1964-1973	6.9%	4.1%	2.8%	6.8%	0.1%
1965-1974	6.1%	3.2%	2.8%	7.2%	-1.1%
1966-1975	4.7%	3.4%	1.3%	7.6%	-2.9%
1967-1976	9.3%	5.1%	4.1%	8.0%	1.3%
1968-1977	9.6%	6.0%	3.6%	8.3%	1.3%
1969-1978	9.2%	6.2%	3.1%	8.6%	0.7%
1970-1979	13.6%	6.1%	7.5%	8.8%	4.8%
1971-1980	13.8%	4.1%	9.7%	9.3%	4.5%
1972-1981	12.2%	2.7%	9.5%	10.3%	1.9%
1973-1982	15.4%	6.9%	8.5%	11.0%	4.3%
1974-1983	17.2%	7.6%	9.6%	11.5%	5.7%
1975-1984	19.5%	9.3%	10.2%	11.9%	7.6%
1976-1985	19.7%	11.6%	8.1%	12.1%	7.5%
1977-1986	17.3%	11.4%	5.9%	12.2%	5.2%
1978-1987	15.9%	10.9%	5.1%	12.3%	3.6%
1979-1988	15.4%	11.8%	3.7%	12.4%	3.0%
1980-1989	12.8%	13.7%	-0.9%	12.4%	0.4%
1981-1990	11.1%	13.8%	-2.7%	12.2%	-1.1%
1982-1991	12.1%	16.5%	-4.5%	11.6%	0.5%
1983-1992	8.9%	13.6%	-4.7%	11.0%	-2.1%
1984-1993	10.4%	14.9%	-4.5%	10.5%	-0.1%
1985-1994	9.2%	12.3%	-3.1%	10.1%	-0.9%
1986-1995	7.2%	12.4%	-5.2%	9.8%	-2.6%
1987-1996	8.8%	12.1%	-3.3%	9.6%	-0.7%
1988-1997	12.0%	13.8%	-1.8%	9.2%	2.8%
1989-1998	11.2%	14.2%	-2.9%	8.7%	2.5%
1990-1999	8.2%	11.8%	-3.6%	8.2%	0.0%
1991-2000	12.8%	12.9%	-0.1%	7.7%	5.1%
1992-2001	13.7%	10.8%	2.9%	7.3%	6.4%
1993-2002	13.7%	10.5%	3.1%	6.9%	6.7%
1994-2003	14.0%	9.0%	5.0%	6.7%	7.3%
1995-2004	14.2%	10.9%	3.3%	6.3%	8.0%
1996-2005	17.7%	9.8%	7.9%	5.9%	11.9%
1997-2006	16.0%	8.7%	7.3%	5.5%	10.5%
1998-2007	13.5%	7.3%	6.2%	5.2%	8.3%
1999-2008	11.1%	7.2%	3.9%	5.1%	6.0%
2000-2009	15.7%	7.5%	8.2%	4.9%	10.9%

Source:
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006 TSX Review

10-YEAR ROLLING AVERAGE RETURNS
FOR U.S. UTILITIES AND GOVERNMENT BONDS

	S&P/Moody's Gas Distributors Returns	S&P/Moody's Electric Returns	US Bond Total Returns	US Gas Risk Premium Bond Total Returns	US Electric Risk Premium Bond Total Returns	US Bond Income Returns	US Gas Risk Premium Bond Income Returns	US Electric Risk Premium Bond Income Returns
1947-1956	12.4%	10.4%	0.8%	11.5%	9.5%	2.5%	9.8%	7.8%
1948-1957	12.6%	12.6%	1.9%	10.8%	10.8%	2.7%	10.0%	10.0%
1949-1958	15.7%	16.3%	0.9%	14.8%	15.4%	2.7%	12.9%	13.6%
1950-1959	12.6%	14.3%	0.0%	12.6%	14.3%	2.9%	9.7%	11.4%
1951-1960	14.6%	16.0%	1.4%	13.2%	14.6%	3.1%	11.5%	12.9%
1952-1961	15.9%	17.2%	1.9%	14.0%	15.3%	3.3%	12.6%	13.9%
1953-1962	14.3%	15.4%	2.5%	11.9%	12.9%	3.4%	10.9%	11.9%
1954-1963	15.0%	15.5%	2.2%	12.8%	13.2%	3.5%	11.5%	12.0%
1955-1964	13.5%	14.7%	1.9%	11.6%	12.8%	3.7%	9.8%	11.0%
1956-1965	12.4%	13.7%	2.1%	10.4%	11.7%	3.8%	8.6%	9.9%
1957-1966	9.9%	13.0%	3.0%	6.9%	10.0%	4.0%	6.0%	9.1%
1958-1967	10.8%	11.7%	1.3%	9.5%	10.4%	4.1%	6.7%	7.6%
1959-1968	8.6%	8.7%	1.9%	6.7%	6.8%	4.3%	4.3%	4.5%
1960-1969	6.9%	6.9%	1.6%	5.2%	5.3%	4.5%	2.4%	2.4%
1961-1970	7.9%	6.0%	1.5%	6.4%	4.6%	4.7%	3.2%	1.3%
1962-1971	4.7%	3.3%	2.7%	2.1%	0.7%	5.0%	-0.3%	-1.6%
1963-1972	6.5%	3.6%	2.6%	4.0%	1.0%	5.2%	1.4%	-1.6%
1964-1973	3.8%	0.7%	2.3%	1.4%	-1.6%	5.4%	-1.7%	-4.7%
1965-1974	2.7%	-3.4%	2.4%	0.3%	-5.8%	5.7%	-3.0%	-9.1%
1966-1975	5.1%	1.4%	3.3%	1.9%	-1.9%	6.1%	-1.0%	-4.8%
1967-1976	11.4%	4.1%	4.6%	6.8%	-0.4%	6.5%	4.9%	-2.3%
1968-1977	11.4%	5.3%	5.4%	6.0%	-0.1%	6.7%	4.7%	-1.4%
1969-1978	9.4%	4.1%	5.3%	4.1%	-1.2%	7.0%	2.4%	-2.9%
1970-1979	14.6%	5.5%	5.7%	8.9%	-0.2%	7.2%	7.4%	-1.8%
1971-1980	14.7%	4.9%	4.1%	10.6%	0.8%	7.6%	7.1%	-2.7%
1972-1981	13.6%	6.7%	3.0%	10.6%	3.8%	8.1%	5.5%	-1.4%
1973-1982	12.0%	9.9%	6.4%	5.6%	3.4%	8.9%	3.2%	1.0%
1974-1983	17.1%	13.1%	6.6%	10.5%	6.5%	9.2%	7.9%	3.8%
1975-1984	18.7%	18.1%	7.7%	11.0%	10.4%	9.7%	9.0%	8.4%
1976-1985	18.2%	15.6%	9.9%	8.3%	5.7%	10.0%	8.2%	5.6%
1977-1986	15.9%	16.0%	10.7%	5.3%	5.4%	10.1%	5.8%	5.9%
1978-1987	14.0%	14.4%	10.5%	3.6%	3.9%	10.2%	3.8%	4.2%
1979-1988	16.4%	16.5%	11.6%	4.8%	4.9%	10.3%	6.1%	6.2%
1980-1989	17.1%	19.8%	13.5%	3.6%	6.3%	10.3%	6.8%	9.4%
1981-1990	13.9%	19.3%	14.5%	-0.6%	4.8%	10.1%	3.8%	9.2%
1982-1991	17.0%	20.3%	16.3%	0.7%	4.0%	9.8%	7.2%	10.5%
1983-1992	19.0%	17.3%	13.0%	5.9%	4.3%	9.2%	9.8%	8.2%
1984-1993	17.2%	17.3%	14.8%	2.5%	2.5%	8.9%	8.4%	8.4%
1985-1994	14.2%	13.5%	12.5%	1.8%	1.0%	8.3%	5.9%	5.1%
1986-1995	15.3%	14.0%	12.5%	2.8%	1.5%	8.0%	7.3%	6.1%
1987-1996	13.9%	11.2%	10.0%	3.9%	1.2%	7.7%	6.2%	3.5%
1988-1997	16.8%	14.6%	11.8%	5.0%	2.8%	7.6%	9.3%	7.0%
1989-1998	14.5%	15.2%	12.2%	2.3%	3.0%	7.2%	7.2%	8.0%
1990-1999	10.0%	10.2%	9.5%	0.5%	0.7%	6.9%	3.1%	3.2%
1991-2000	12.7%	15.8%	11.0%	1.7%	4.8%	6.8%	5.9%	9.1%
1992-2001	11.0%	12.3%	9.4%	1.6%	2.9%	6.5%	4.6%	5.8%
1993-2002	9.8%	10.6%	10.4%	-0.6%	0.2%	6.3%	3.5%	4.3%
1994-2003	10.1%	11.1%	8.7%	1.3%	2.4%	6.1%	4.0%	5.1%
1995-2004	12.8%	14.0%	10.4%	2.4%	3.7%	5.9%	6.8%	8.1%
1996-2005	9.6%	11.7%	8.0%	1.6%	3.7%	5.6%	3.9%	6.0%
1997-2006	10.7%	13.6%	8.2%	2.5%	5.4%	5.5%	5.2%	8.1%
1998-2007	8.8%	12.3%	7.6%	1.2%	4.7%	5.3%	3.5%	7.0%
1999-2008	9.6%	7.3%	8.9%	0.8%	-1.6%	5.2%	4.5%	2.1%
2000-2009	9.8%	10.4%	7.5%	2.3%	2.8%	5.0%	4.8%	5.3%

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
www.standardandpoors.com, Mergent Corporate News Reports,
www.federal reserve.com

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES

	Value Line							S & P		Moody's
	Safety	Forecast Common Equity Ratio 2012-2014	Forecast Return On Average Common Equity 2012-2014	Dividend Payout Forecast 2012-2014	2009 Q4 Beta	Calculated Weekly Betas 1/	Common Equity Ratio 2008	Business Risk Profile	Debt Rating	Debt Rating 2/
AGL Resources	2	49.0%	13.6%	57.0%	0.75	0.67	39.4%	Excellent	A-	Baa1
Consolidated Edison	1	51.5%	9.5%	63.4%	0.65	0.45	48.5%	Excellent	A-	Baa1
New Jersey Resources	1	66.5%	11.7%	53.3%	0.65	0.53	51.2%	Excellent	A	Aa3
Nicor Inc.	3	74.0%	12.0%	60.0%	0.75	0.71	44.0%	Excellent	AA	A2
Northwest Nat. Gas	1	53.0%	11.6%	61.4%	0.60	0.46	45.3%	Excellent	AA-	A3
NSTAR	1	53.5%	15.2%	60.0%	0.65	0.52	36.8%	Excellent	A+	A2
Piedmont Natural Gas	2	52.0%	14.3%	58.6%	0.65	0.55	41.9%	Excellent	A	A3
South Jersey Inds.	2	63.5%	14.9%	50.8%	0.65	0.52	47.5%	Excellent	BBB+	Baa1
WGL Holdings Inc.	1	64.0%	10.8%	59.3%	0.65	0.55	51.7%	Excellent	AA-	A2
Mean	**2**	**58.6%**	**12.6%**	**58.2%**	**0.67**	**0.55**	**45.1%**	**Excellent**	**A**	**A3**
Median	**1**	**53.5%**	**12.0%**	**59.3%**	**0.65**	**0.53**	**45.3%**	**Excellent**	**A**	**A3**

1/ "Raw" betas calculated using weekly data against the NYSE Composite (260 weeks ending December 28, 2009).
2/ Rating for New Jersey Resources is New Jersey Natural Gas. Rating for South Jersey Industries is South Jersey Gas Co. Rating for WGL Holdings is Washington Gas Light. Rating for Nicor Inc. is for Northern Illinois Gas.

Source: Standard and Poor's Research Insight, Value Line (November and December 2009), January 8, 2010 Value Line Index, www.Moodys.com, www.yahoo.com,
Standard and Poor's, *Issuer Ranking: U.S. Invester-Owned Electric Utilities, Strongest To Weakest* (December 28, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (January 12, 2010).

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield [1/]	Average I/B/E/S/ Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	35.70	5.0	4.0	9.0
Consolidated Edison	2.36	43.77	5.6	3.4	9.0
New Jersey Resources	1.36	36.53	4.0	7.0	11.0
Nicor Inc.	1.86	40.42	4.8	4.4	9.2
Northwest Nat. Gas	1.66	44.08	4.0	6.0	10.0
NSTAR	1.60	34.44	4.9	5.6	10.5
Piedmont Natural Gas	1.08	25.15	4.6	6.6	11.2
South Jersey Inds.	1.32	37.31	3.9	11.5	15.4
WGL Holdings Inc.	1.47	32.80	4.7	5.0	9.7
Mean	**1.60**	**36.69**	**4.6**	**5.9**	**10.6**
Median	**1.60**	**36.53**	**4.7**	**5.6**	**10.0**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (December 2009)

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DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Dividend Paid	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield 1/	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth 2/ (4th Qtr.2009)	SV Growth 3/ (4th Qtr. 2009)	Sustainable Growth 4/ (4th Qtr. 2009)	DCF Cost of Equity 5/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL RESOURCES INC	1.72	35.70	5.1	13.6	43.0	5.8	0.38	6.2	11.3
CONSOLIDATED EDISON	2.36	43.77	5.6	9.5	36.6	3.5	0.15	3.6	9.2
NEW JERSEY RESOURCES	1.36	36.53	3.9	11.7	46.7	5.4	0.51	5.9	9.9
NICOR INC	1.86	40.42	4.8	12.0	40.0	4.8	0.08	4.9	9.7
NORTHWEST NATURAL GAS CO	1.66	44.08	4.0	11.6	38.6	4.5	0.57	5.0	9.0
NSTAR	1.60	34.44	4.9	15.2	40.0	6.1	0.00	6.1	11.0
PIEDMONT NATURAL GAS CO	1.08	25.15	4.5	14.3	41.4	5.9	-0.54	5.4	9.9
SOUTH JERSEY INDUSTRIES INC	1.32	37.31	3.8	14.9	49.2	7.3	0.72	8.1	11.9
WGL HOLDINGS INC	1.47	32.80	4.7	10.8	40.7	4.4	0.01	4.4	9.1
Mean	**1.60**	**36.69**	**4.60**	**12.62**	**41.80**	**5.31**	**0.21**	**5.5**	**10.1**
Median	**1.60**	**36.53**	**4.68**	**12.00**	**40.73**	**5.44**	**0.15**	**5.4**	**9.9**

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
2/ BR Growth = Col (4) * (Col (5) / 100)
3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity
financing that accrues to existing shareholders [1- B/M]
4/ Col (6) + Col (7)
5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: Standard and Poors Research Insight, *Value Line* (November and December 2009) , www.yahoo.com

DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES
(THREE-STAGE MODEL)

			Growth Rates			
Company	**Annualized Last Paid Dividend**	**Average High/Low Monthly Close Prices 11/1/2009-1/26/2010**	**Stage 1: I/B/E/S EPS Forecasts**	**Stage 2: Average of Stage 1 & 3**	**Stage 3: GDP Growth** 1/	**DCF Cost of Equity** 2/
	(1)	(2)	(3)	(4)		(5)
AGL RESOURCES INC	1.72	35.70	4.0	4.5	5.0	9.7
CONSOLIDATED EDISON	2.36	43.77	3.4	4.2	5.0	10.1
NEW JERSEY RESOURCES	1.36	36.53	7.0	6.0	5.0	9.3
NICOR INC	1.86	40.42	4.4	4.7	5.0	9.6
NORTHWEST NATURAL GAS CO	1.66	44.08	6.0	5.5	5.0	9.1
NSTAR	1.60	34.44	5.6	5.3	5.0	10.0
PIEDMONT NATURAL GAS CO	1.08	25.15	6.6	5.8	5.0	9.9
SOUTH JERSEY INDUSTRIES INC	1.32	37.31	11.5	8.3	5.0	10.4
WGL HOLDINGS INC	1.47	32.80	5.0	5.0	5.0	9.6
Mean	**1.60**	**36.69**	**5.9**	**5.5**	**5.0**	**9.8**
Median	**1.60**	**36.53**	**5.6**	**5.3**	**5.0**	**9.7**

1/ Forecast nominal rate of GDP growth, 2011-20
2/ Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip Financial Forecasts (December 2009); I/B/E/S (December 2009)

MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF CANADIAN DISTRIBUTION UTILITIES AND U.S. UTILITIES

	Debt and Preferred Shares at Par in Millions (September 2009)	Common Share Price Average High/Low Monthly Close 11/1/2009-1/26/2010	Common Shares Outstanding in Millions (December 2009)	Total Market Capitalization	Market Value Common Equity Ratio
Canadian Utilities	3,992	42.17	126	5,299	57.0%
Emera Inc.	2,784	23.97	113	2,697	49.2%
Enbridge Inc.	11,861	45.99	376	17,269	59.3%
Fortis Inc.	6,382	27.43	171	4,683	42.3%
Transcanada Corp.	20,883	34.46	684	23,557	53.0%
Mean				**$10,701**	**52.2%**
Median				**$5,299**	**53.0%**

MARKET VALUE CAPITAL STRUCTURES FOR U.S. UTILITIES

	Debt and Preferred Shares at Par in Millions $ (September 2009)	Common Share Price Average High/Low Monthly Close 11/1/2009-1/26/2010	Common Shares Outstanding in Millions (September 2009)	Total Market Capitalization in Millions $	Market Value Common Equity Ratio
AGL Resources	2,285	35.70	77	2,745	54.6%
Consolidated Edison	10,973	43.77	275	12,040	52.3%
New Jersey Resources	605	36.53	42	1,519	71.5%
Nicor Inc.	864	40.42	45	1,835	68.0%
Northwest Nat. Gas	709	44.08	27	1,169	62.2%
NSTAR	2,887	34.44	107	3,679	56.0%
Piedmont Natural Gas	1,099	25.15	73	1,842	62.6%
South Jersey Inds.	1,042	37.31	30	1,112	51.6%
WGL Holdings Inc.	856	32.80	50	1,645	65.8%
Mean				**$3,065**	**60.5%**
Median				**$1,835**	**62.2%**

Source: Annual Reports to Shareholders, Standard & Poor's Research Insight, www.yahoo.com

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: CANADIAN UTILITIES

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
	=	6.30%
Equity Cost	=	CAPM Cost of Equity
	=	9.25%
Tax Rate	=	28.4%
CEQ Ratio	(1)	53.0%
Debt Ratio	(1)	47.0%
CEQ Ratio	(2)	40.0%
Debt Ratio	(2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 53.0%)

   $WACC_{AT}$ = (6.30%)(1-.284)(47.0%) + (9.25%)(53.0%)
   = 7.02%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio wit $WACC_{AT}$ unchanged at 7.02%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.02% = (6.30%)(1-.284)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 10.79%

3. Difference between Equity Return at 53.0% and 40.0% common equity ratios:

   10.79% - 9.25% = 1.54% (154 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
	=	6.30%
Equity Cost	=	Cost of Equity
	=	9.25%
Tax Rate	=	28.4%
CEQ Ratio	(1)	53.0%
Debt Ratio	(1)	47.0%
CEQ Ratio	(2)	40.0%
Debt Ratio	(2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 53.0%)

$WACC_{AT}$ = (6.30%)(1-.284)(47.0%) + (9.25%)(53.0%)
= 7.02%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1\text{-t x Debt Ratio}_{ML})/(1\text{-t x Debt Ratio}_{LL})$

$$WACC_{AT(ML)} = 7.02\% \times \frac{(1-.284 \times 60.0\%)}{(1-.284 \times 47.0\%)}$$

$WACC_{AT(ML)}$ = 6.72%

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})
6.72% = (6.30%)(1-.284)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 10.04%

4. Difference between Equity Return at 53.0% and 40.0% common equity ratios:

10.04% - 9.25% = 0.79% (79 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
79-154 Basis Points (Midpoint of 116)

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES

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
	=	6.30%
Equity Cost	=	Midpoint of DCF-Based Risk Premium and DCF Cost of Equity Test Results
	=	9.70%
Tax Rate	=	28.4%
CEQ Ratio	(1)	62.0%
Debt Ratio	(1)	38.0%
CEQ Ratio	(2)	48.0%
Debt Ratio	(2)	52.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 62.0%)

   $WACC_{AT}$ = (6.30%)(1-.284)(38.0%) + (9.70%)(62.0%)
   = 7.73%

2. Estimate Cost of Equity for sample at 48.0% common equity ratio with $WACC_{AT}$ unchange(at 7.73%

   Tax Rate Declines to Canadian Level

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.73% = (6.30%)(1-.284)(52.0%) + (X)(48.0%)
   Cost of Equity at 48.0% Equity Ratio = 11.21%

3. Difference between Equity Return at 62.0% and 48.0% common equity ratios:

   11.21% - 09.70% = 1.51% (151 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
	=	6.30%
Equity Cost	=	Cost of Equity
	=	9.70%
Tax Rate	=	28.4%
CEQ Ratio	(1)	62.0%
Debt Ratio	(1)	38.0%
CEQ Ratio	(2)	48.0%
Debt Ratio	(2)	52.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 62.0%)

$WACC_{AT}$ = (6.30%)(1-.284)(38.0%) + (9.70%)(62.0%)
= 7.73%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 48.0%)
Tax Rate Declines to Canadian Level

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 7.73\% \times \frac{(1-.284 \times 52.0\%)}{(1-.284 \times 38.0\%)}$$

$WACC_{AT(ML)}$ = 7.38%

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 $Ratio_{ML}$)
7.38% = (6.30%)(1-.284)(52.0%) + (X)(48.0%)
Cost of Equity at 48.0% Equity Ratio = 10.50%

4. Difference between Equity Return at 62.0% and 48.0% common equity ratios:
10.50% - 09.70% = 0.80% (80 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
Approximately 80 to 151 basis points (Midpoint of 116)

INDIVIDUAL COMPANY RISK DATA FOR BBB RATED SAMPLE OF U.S. UTILITIES

	Value Line							S & P		Moody's
	Safety	**Forecast Common Equity Ratio 2012-2014**	**Forecast Return On Average Common Equity 2012-2014**	**Dividend Payout Forecast 2012-2014**	**2009 Q4 Beta**	**Calculated Weekly Betas 1/**	**Common Equity Ratio 2008**	**Business Risk Profile**	**Debt Rating**	**Debt Rating 2/**
ALLETE	2	51.0%	9.9%	69.1%	0.70	0.58	57.8%	Strong	BBB+	Baa1
Alliant Energy	2	58.5%	10.2%	61.9%	0.70	0.69	56.0%	Excellent	BBB+	Baa1
Ameren Corp.	3	54.0%	8.2%	56.7%	0.80	0.78	45.6%	Satisfactory	BBB-	Baa3
Atmos Energy	2	51.0%	9.5%	56.0%	0.65	0.60	45.4%	Excellent	BBB+	Baa2
Black Hills	3	59.5%	9.6%	52.0%	0.80	0.77	46.5%	Satisfactory	BBB-	Baa3
Constellation Energy	3	53.0%	10.0%	28.6%	0.80	0.65	26.7%	Satisfactory	BBB-	Baa3
DTE Energy	3	45.0%	10.2%	58.8%	0.75	0.73	40.4%	Strong	BBB	Baa2
Entergy Corp.	2	42.0%	14.5%	45.0%	0.70	0.56	38.8%	Strong	BBB	Baa3
Exelon Corp.	1	57.0%	20.0%	48.0%	0.85	0.86	45.5%	Strong	BBB	Baa1
FirstEnergy Corp.	2	47.5%	14.5%	52.0%	0.80	0.69	37.2%	Strong	BBB	Baa3
Hawaiian Elec.	3	55.5%	10.6%	70.9%	0.70	0.61	41.9%	Strong	BBB	Baa1
OGE Energy	2	46.5%	12.0%	49.2%	0.75	0.77	43.5%	Strong	BBB+	Baa1
Pepco Holdings	3	48.0%	7.8%	67.5%	0.80	0.92	41.4%	Strong	BBB	Baa3
PG&E Corp.	2	54.0%	12.2%	51.8%	0.55	0.45	43.8%	Excellent	BBB+	Baa1
Pinnacle West Capital	3	52.0%	8.8%	67.7%	0.75	0.64	47.0%	Strong	BBB-	Baa3
Portland General	2	50.0%	8.6%	60.0%	0.70	0.57	47.3%	Strong	BBB+	Baa2
PPL Corp.	3	45.5%	20.2%	50.7%	0.70	0.68	36.5%	Satisfactory	BBB	Baa2
Public Serv. Enterprise	3	57.0%	16.3%	45.3%	0.80	0.66	46.0%	Strong	BBB	Baa2
Sempra Energy	2	57.0%	12.2%	35.0%	0.85	0.75	50.6%	Strong	BBB+	Baa1
South Jersey Inds.	2	63.5%	14.9%	50.8%	0.65	0.52	47.5%	Excellent	BBB+	Baa1
Xcel Energy Inc.	2	48.5%	10.8%	55.0%	0.65	0.48	44.0%	Excellent	BBB+	Baa1
Mean	**2**	**52.2%**	**11.9%**	**53.9%**	**0.74**	**0.67**	**44.3%**	**Strong**	**BBB**	**Baa2**
Median	**2**	**52.0%**	**10.6%**	**52.0%**	**0.75**	**0.66**	**45.4%**	**Strong**	**BBB**	**Baa2**

1/ "Raw" betas calculated using weekly data against the NYSE Composite (260 weeks ending December 28, 2009). Portland General only has data for 187 weeks.
2/ Rating for South Jersey Industries is South Jersey Gas Co.

Source: Standard and Poor's Research Insight, Value Line (November and December 2009), January 8, 2010 Value Line Index, www.Moodys.com, www.yahoo.com,
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (December 28, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (January 12, 2010).
Standard and Poor's, *Issuer Ranking: U.S. Energy Merchants/Power Developers/Trading and Marketing Companies, Strongest to Weakest (November 5, 2009).*

VALUE LINE BETAS FOR BENCHMARK AND BBB RATED SAMPLES OF U.S. UTILITIES

Company	4Q 2005	4Q 2006	4Q 2007	4Q 2008	4Q 2009	Average
Benchmark Sample						
AGL RESOURCES INC	0.90	0.95	0.85	0.75	0.75	0.84
CONSOLIDATED EDISON	0.60	0.75	0.75	0.65	0.65	0.68
NEW JERSEY RESOURCES	0.75	0.80	0.85	0.70	0.65	0.75
NICOR INC	1.10	1.30	1.00	0.70	0.75	0.97
NORTHWEST NATURAL GAS CO	0.70	0.75	0.90	0.60	0.60	0.71
NSTAR	0.75	0.80	0.75	0.70	0.65	0.73
PIEDMONT NATURAL GAS CO	0.75	0.80	0.85	0.70	0.65	0.75
SOUTH JERSEY INDUSTRIES INC	0.65	0.70	0.85	0.75	0.65	0.72
WGL HOLDINGS INC	0.80	0.85	0.85	0.75	0.65	0.78
Mean	**0.78**	**0.86**	**0.85**	**0.70**	**0.67**	**0.77**
Median	**0.75**	**0.80**	**0.85**	**0.70**	**0.65**	**0.75**
Average of Annual Medians						**0.75**
BBB Rated Sample						
ALLETE	nmf	0.90	0.95	0.75	0.70	0.83
ALLIANT ENERGY	0.85	0.95	0.80	0.70	0.70	0.80
AMEREN CORP	0.75	0.75	0.80	0.80	0.80	0.78
ATMOS ENERGY	0.70	0.80	0.85	0.65	0.65	0.73
BLACK HILLS	1.00	1.05	1.10	0.85	0.80	0.96
CONSTELLATION ENERGY	0.95	0.95	0.85	0.75	0.80	0.86
DTE ENERGY	0.70	0.75	0.80	0.70	0.75	0.74
ENTERGY CORP	0.80	0.85	0.85	0.75	0.70	0.79
EXELON CORP	0.75	0.90	0.90	0.90	0.85	0.86
FIRSTENERGY CORP	0.75	0.80	0.85	0.85	0.80	0.81
HAWAIIAN ELECTRIC	0.70	0.70	0.70	0.75	0.70	0.71
OGE ENERGY	0.75	0.75	0.85	0.75	0.75	0.77
PEPCO HOLDINGS	0.90	0.90	0.95	0.75	0.80	0.86
PG&E CORP	1.10	1.15	0.95	0.85	0.55	0.92
PINNACLE WEST CAPITAL	0.90	1.00	1.00	0.75	0.75	0.88
PORTLAND GENERAL	na	nmf	nmf	0.70	0.70	0.70
PPL CORP	1.00	0.95	0.90	0.80	0.70	0.87
PUBLIC SERVICE ENTERPRISE GROU	0.90	1.00	0.95	0.85	0.80	0.90
SEMPRA ENERGY	1.00	1.10	1.00	0.90	0.85	0.97
SOUTH JERSEY INDUSTRIES	0.65	0.70	0.85	0.75	0.65	0.72
XCEL ENERGY	0.80	0.90	1.05	0.75	0.65	0.83
Mean	**0.84**	**0.89**	**0.90**	**0.78**	**0.74**	**0.82**
Median	**0.80**	**0.90**	**0.88**	**0.75**	**0.75**	**0.83**
Average of Annual Medians						**0.82**

Source: *Value Line* 4th Quarter Issues

DCF COST OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield [1/]	Average I/B/E/S/ Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
ALLETE	1.76	32.95	5.6	4.0	9.6
Alliant Energy	1.50	29.46	5.3	4.3	9.6
Ameren Corp.	1.54	26.35	6.0	3.0	9.0
Atmos Energy	1.34	28.64	4.9	5.0	9.9
Black Hills	1.42	25.45	5.9	6.0	11.9
Constellation Energy	0.96	33.35	3.3	14.8	18.1
DTE Energy	2.12	41.53	5.3	3.0	8.3
Entergy Corp.	3.00	80.19	4.0	6.8	10.8
Exelon Corp.	2.10	48.40	4.4	2.2	6.6
FirstEnergy Corp.	2.20	44.53	5.1	3.3	8.4
Hawaiian Elec.	1.24	20.22	6.8	10.5	17.3
OGE Energy	1.45	35.30	4.4	6.0	10.4
Pepco Holdings	1.08	16.44	6.9	5.5	12.4
PG&E Corp.	1.68	43.49	4.1	7.3	11.5
Pinnacle West Capital	2.10	35.56	6.4	8.0	14.4
Portland General	1.02	19.91	5.5	6.8	12.3
PPL Corp.	1.38	31.17	4.9	11.5	16.4
Public Serv. Enterprise	1.33	31.92	4.4	5.3	9.7
Sempra Energy	1.56	53.45	3.1	7.0	10.1
South Jersey Inds.	1.32	37.31	3.9	11.5	15.4
Xcel Energy Inc.	0.98	20.63	5.1	7.3	12.4
Mean	**1.58**	**35.06**	**5.0**	**6.6**	**11.6**
Median	**1.45**	**32.95**	**5.1**	**6.0**	**10.8**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (December 2009)

Schedule 25

DCF COSTS OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Dividend Paid	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield [1/]	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth [2/] (4th Qtr.2009)	SV Growth [3/] (4th Qtr. 2009)	Sustainable Growth [4/] (4th Qtr. 2009)	DCF Cost of Equity [5/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ALLETE	1.76	32.95	5.6	9.9	30.9	3.1	1.53	4.6	10.2
Alliant Energy	1.50	29.46	5.3	10.2	38.1	3.9	0.22	4.1	9.4
Ameren Corp.	1.54	26.35	6.1	8.2	43.3	3.6	0.02	3.6	9.6
Atmos Energy	1.34	28.64	4.9	9.5	44.0	4.2	0.90	5.1	10.0
Black Hills	1.42	25.45	5.8	9.6	48.0	4.6	0.01	4.6	10.5
Constellation Energy	0.96	33.35	3.1	10.0	71.4	7.1	0.14	7.3	10.4
DTE Energy	2.12	41.53	5.3	10.2	41.2	4.2	0.27	4.5	9.8
Entergy Corp.	3.00	80.19	4.0	14.5	55.0	8.0	-0.48	7.5	11.5
Exelon Corp.	2.10	48.40	4.8	20.0	52.0	10.4	-0.43	10.0	14.8
FirstEnergy Corp.	2.20	44.53	5.3	14.5	48.0	6.9	0.00	6.9	12.2
Hawaiian Elec.	1.24	20.22	6.3	10.6	29.1	3.1	0.19	3.3	9.6
OGE Energy	1.45	35.30	4.4	12.0	50.8	6.1	0.50	6.6	11.0
Pepco Holdings	1.08	16.44	6.7	7.8	32.5	2.5	-0.72	1.8	8.5
PG&E Corp.	1.68	43.49	4.1	12.2	48.2	5.9	0.51	6.4	10.5
Pinnacle West Capital	2.10	35.56	6.1	8.8	32.3	2.9	0.22	3.1	9.2
Portland General	1.02	19.91	5.3	8.6	40.0	3.4	0.25	3.7	9.0
PPL Corp.	1.38	31.17	4.9	20.2	49.3	10.0	-0.14	9.8	14.7
Public Serv. Enterprise	1.33	31.92	4.5	16.3	54.7	8.9	-0.30	8.6	13.2
Sempra Energy	1.56	53.45	3.2	12.2	65.0	7.9	0.21	8.1	11.3
South Jersey Inds.	1.32	37.31	3.8	14.9	49.2	7.3	0.72	8.1	11.9
Xcel Energy Inc.	0.98	20.63	5.0	10.8	45.0	4.9	0.06	4.9	9.9
Mean	**1.58**	**35.06**	**4.97**	**11.95**	**46.10**	**5.66**	**0.17**	**5.8**	**10.8**
Median	**1.45**	**32.95**	**4.98**	**10.61**	**48.00**	**4.85**	**0.19**	**5.1**	**10.4**

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
2/ BR Growth = Col (4) * (Col (5) / 100)
3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M]
4/ Col (6) + Col (7)
5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: Standard and Poors Research Insight, *Value Line* (November and December 2009) , www.yahoo.com

DCF COSTS OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Growth Rates: Stage 1: I/B/E/S EPS Forecasts	Growth Rates: Stage 2: Average of Stage 1 & 3	Growth Rates: Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)		(5)
ALLETE	1.76	32.95	4.0	4.5	5.0	10.2
Alliant Energy	1.50	29.46	4.3	4.7	5.0	10.1
Ameren Corp.	1.54	26.35	3.0	4.0	5.0	10.4
Atmos Energy	1.34	28.64	5.0	5.0	5.0	9.9
Black Hills	1.42	25.45	6.0	5.5	5.0	11.2
Constellation Energy	0.96	33.35	14.8	9.9	5.0	10.4
DTE Energy	2.12	41.53	3.0	4.0	5.0	9.7
Entergy Corp.	3.00	80.19	6.8	5.9	5.0	9.3
Exelon Corp.	2.10	48.40	2.2	3.6	5.0	8.7
FirstEnergy Corp.	2.20	44.53	3.3	4.2	5.0	9.6
Hawaiian Elec.	1.24	20.22	10.5	7.8	5.0	13.7
OGE Energy	1.45	35.30	6.0	5.5	5.0	9.5
Pepco Holdings	1.08	16.44	5.5	5.3	5.0	12.1
PG&E Corp.	1.68	43.49	7.3	6.2	5.0	9.6
Pinnacle West Capital	2.10	35.56	8.0	6.5	5.0	12.3
Portland General	1.02	19.91	6.8	5.9	5.0	11.0
PPL Corp.	1.38	31.17	11.5	8.2	5.0	11.7
Public Serv. Enterprise	1.33	31.92	5.3	5.2	5.0	9.4
Sempra Energy	1.56	53.45	7.0	6.0	5.0	8.3
South Jersey Inds.	1.32	37.31	11.5	8.3	5.0	10.4
Xcel Energy Inc.	0.98	20.63	7.3	6.1	5.0	10.7
Mean	**1.58**	**35.06**	**6.6**	**5.8**	**5.0**	**10.4**
Median	**1.45**	**32.95**	**6.0**	**5.5**	**5.0**	**10.2**

1/ Forecast nominal rate of GDP growth, 2011-20
2/ Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip Financial Forecasts (December 2009); I/B/E/S (December 2009)

COMMON EQUITY RATIOS FOR BENCHMARK AND BBB RATED SAMPLES OF U.S. UTILITIES

Company	2004	2005	2006	2007	2008	Average
Benchmark Sample						
AGL RESOURCES INC	41%	41%	43%	42%	39%	41%
CONSOLIDATED EDISON	49%	46%	47%	49%	48%	48%
NEW JERSEY RESOURCES	44%	47%	50%	50%	51%	48%
NICOR INC	43%	42%	51%	52%	44%	46%
NORTHWEST NATURAL GAS CO	49%	47%	48%	47%	45%	47%
NSTAR	37%	34%	34%	36%	37%	36%
PIEDMONT NATURAL GAS CO	53%	52%	47%	46%	42%	48%
SOUTH JERSEY INDUSTRIES INC	45%	45%	44%	50%	47%	46%
WGL HOLDINGS INC	52%	56%	52%	54%	52%	53%
Mean	**46%**	**46%**	**46%**	**47%**	**45%**	**46%**
Median	**45%**	**46%**	**47%**	**49%**	**45%**	**47%**
Average of Annual Medians						**46%**
BBB Rated Sample						
ALLETE	62%	61%	63%	64%	58%	61%
ALLIANT ENERGY	48%	48%	58%	59%	56%	54%
AMEREN CORP	49%	52%	50%	47%	46%	49%
ATMOS ENERGY	57%	41%	39%	46%	45%	46%
BLACK HILLS	48%	50%	50%	57%	47%	50%
CONSTELLATION ENERGY	46%	49%	47%	50%	27%	44%
DTE ENERGY	39%	40%	39%	41%	40%	40%
ENTERGY CORP	50%	44%	46%	41%	39%	44%
EXELON CORP	41%	39%	43%	42%	45%	42%
FIRSTENERGY CORP	43%	45%	44%	43%	37%	43%
HAWAIIAN ELECTRIC	28%	29%	27%	29%	42%	31%
OGE ENERGY	45%	50%	54%	51%	44%	49%
PEPCO HOLDINGS	36%	39%	39%	43%	41%	40%
PG&E CORP	47%	40%	43%	44%	44%	44%
PINNACLE WEST CAPITAL	47%	53%	51%	49%	47%	50%
PORTLAND GENERAL	58%	57%	53%	50%	47%	53%
PPL CORP	35%	37%	39%	41%	37%	38%
PUBLIC SERVICE ENTERPRISE GROU	29%	32%	37%	42%	46%	37%
SEMPRA ENERGY	47%	49%	56%	58%	51%	52%
SOUTH JERSEY INDUSTRIES	45%	45%	44%	50%	47%	46%
XCEL ENERGY	42%	42%	44%	44%	44%	43%
Mean	**45%**	**45%**	**46%**	**47%**	**44%**	**45%**
Median	**46%**	**45%**	**44%**	**46%**	**45%**	**44%**
Average of Annual Medians						**46%**

Source: Standard and Poor's Research Insight

MULTI-PIPELINE AND REVISED FORMULA PIPELINE ROEs

	Forecast Long Canada Underlying NEB ROE [1/]	Change in Forecast Long Canada From 1995	NEB ROE per RH-2-94	Sept/Oct Corporate Yield Spread [1/]	Change in Yield Spread from 1995	50% of Change in Long Canadas	50% of Change in Corporate Bond Yields	ROE Incorporating Change in Both Long Canadas and Corporate Bond Yields
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1994								
1995	**9.25**		**12.25**	0.71				
1996	8.03	-1.22	11.25	0.42	-0.29	-0.61	-0.14	11.50
1997	7.14	-2.11	10.67	0.27	-0.45	-1.06	-0.22	10.97
1998	6.53	-2.72	10.21	0.28	-0.43	-1.36	-0.21	10.68
1999	5.69	-3.56	9.58	0.99	0.27	-1.78	0.14	10.61
2000	6.12	-3.13	9.90	0.94	0.23	-1.57	0.11	10.80
2001	5.73	-3.52	9.61	1.56	0.84	-1.76	0.42	10.91
2002	5.63	-3.62	9.53	1.31	0.60	-1.81	0.30	10.74
2003	5.98	-3.27	9.79	1.32	0.61	-1.64	0.31	10.92
2004	5.68	-3.57	9.56	0.97	0.26	-1.79	0.13	10.59
2005	5.55	-3.70	9.46	0.98	0.26	-1.85	0.13	10.53
2006	4.78	-4.47	8.88	0.96	0.25	-2.24	0.13	10.14
2007	4.22	-5.03	8.46	1.07	0.36	-2.52	0.18	9.91
2008	4.55	-4.70	8.71	1.18	0.47	-2.35	0.23	10.13
2009	4.36	-4.89	8.57	2.58	1.87	-2.45	0.93	10.74
2010	4.30	-4.95	8.52	1.84	1.13	-2.48	0.56	10.34
2011F [2/]	4.70	-4.55	8.82	1.72	1.01	-2.28	0.50	10.48
Average 1996-2009			**9.6**					**10.7**

[1/] Spread represents differential between Dex A rated Long-term Corporate Bond Index and benchmark Government of Canada bond yield.

[2/] 2011 Long Canada based on January 2010 Consensus Economics, *Consensus Forecasts* ' 4.1% 10-year Canada bond yield forecast for January 2011 plus a January 2010 daily average spread between 10-year and 30-year Canada bond yields of 0.56% . Corporate spread for 2011 is average of spreads at the end of December 2009 and January 2010.

Source: NEB Decisions, Bank of Canada, PC Bond Analytics (TSX Group Inc.)

Northland Utilities (NWT) Limited

Prepared Testimony

of

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FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of, and a senior consultant with, Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, oil and gas pipelines, and telephone companies in more than 150 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Northland Utilities (NWT) Limited (NUNWT) has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity for the Company's 2008-2010 test years.

In Decision 13-2007 (August 2007) for Northwest Territories Power Corporation (NTPC), the Public Utilities Board of the Northwest Territories ("PUB" or "Board") stated that "the Board would prefer to see all of the business risk adjustment reflected in the capital structure rather than in the capital structure as well as in the return on common equity."[1] In recognition of the PUB's preference, I have estimated capital structures that fully reflect the business risks of NUNWT. Based on my analysis, the common equity ratio that would fully compensate for the business risks of NUNWT lies at the upper end of a range of 50-55%.

At a common equity ratio of 55%, the allowed return on equity for NUNWT should be equal to that applicable to an average risk Canadian utility, that is, a benchmark return on equity. For the express purpose of this proceeding, I recommend adopting the benchmark

[1] Public Utilities Board of the Northwest Territories, *In the Matter of an Application by Northwest Territories Power Corporation*, Decision 13-2007 (August 29, 2007), page 47

return on equity derived from the PUB's Decision 13-2007, adjusted for changes in interest rates. The benchmark return on equity adopted by the PUB was 8.75%, based on a long-term Canada bond yield of approximately 4.6%.

With respect to the return on equity for test years 2008-2010, I recommend that the PUB:

1. Adopt a simple return on equity for all three test years, based on the forecast average long-term Government of Canada bond yield of 5.0%; and,

2. Apply the automatic adjustment formula adopted by various Canadian regulators using the 8.75% benchmark return on equity and 4.6% long-term Canada bond yields adopted in Decision 13-2007 as points of departure.

The application of the automatic adjustment formula at a forecast long-term Canada bond yield of 5.0% results in a benchmark return on equity of 9.1%. The indicated benchmark return on equity of 9.1% is applicable to NUNWT at a common equity ratio of 55%.

However, increasing the actual common equity ratio of NUNWT to 55% could require shareholders to raise additional debt capital to effect the change, thus exposing them to incremental financial risks. Moreover, requiring shareholders to commit additional equity capital to have the opportunity to earn a benchmark equity return regarded as too low is fundamentally incongruous. As a result, I recommend increasing the actual common equity ratio of NUNWT to 50% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 50% equity ratio and the 55% common equity ratio that would fully compensate for the business risks of NUNWT. At a common equity ratio of 50%, the allowed ROE for NUNWT should be set at 9.6%.

II. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN COST OF CAPITAL AND CAPITAL STRUCTURE

The cost of capital is largely a function of business risk, that is, of the risks arising from the operations/assets of a firm. The cost of capital, however, is also a function of financial risk, i.e., additional risk borne by the common equity shareholder because the firm is using fixed obligation securities (e.g., long-term debt) to finance a portion of its assets. Therefore, the capital structure, comprised of fixed obligation securities and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used.

However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will accompany an increase in the cost of equity.

B. APPROACHES TO DETERMINING THE FAIR RETURN ON EQUITY

Recognizing the relationship between the cost of capital and capital structure, there are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks, then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or benchmark. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an

adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines.[2] It is also the approach that was adopted by the Alberta Energy and Utilities Board (EUB) in Decision 2004-052 (July 2, 2004). In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/EUB approach as long as the combination of actual/allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark return on equity. The combination of capital structures and equity risk premiums has also been used in Ontario and Québec.

In recognition of the PUB's preference to reflect differences in business risk through capital structure alone, I have estimated the capital structure that fully reflects the business risks of NUNWT. In other words, I have estimated a capital structure for

[2] In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002, 36% in 2005 and 40% in 2007.

NUNWT, based on the principles set out in Section III, that would be compatible with the application of a benchmark return on equity to NUNWT.

C. BENCHMARK RETURN ON EQUITY

1. Conceptual Considerations

Both approaches to determining a fair return outlined in Section II.A rely on the measurement of the equity return that would be applicable to a benchmark utility or average risk Canadian utility. That return will be referred to as a benchmark return on equity. A capital structure for NUNWT would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return; and (c) would equate the level of total (business and financial) risk faced by NUNWT to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the common equity ratio for NUNWT is established so that no adjustment to the benchmark return on equity is required.[3]

The term benchmark utility is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the benchmark utility reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve a particular debt rating, typically an A rating. The typical, average risk Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's (S&P).

[3] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999.

Designation of a debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would require lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return on equity.

In Decision 13-2007, the PUB established a return on equity for NTPC for 2007/08 of 9.25%. The allowed return on equity of 9.25% expressly included a 50 basis point upward adjustment to compensate for the relatively higher risk of NTPC. As noted at page 43 of the decision, the 50 basis point additional risk premium was adopted for NTPC in relation to the return on equity applicable to a benchmark utility. From these findings, it may be reasonably inferred that the PUB considered a return on equity of 8.75% (at a long-term Canada bond yield of 4.50-4.65%[4]) to be equivalent to a benchmark return on equity.

[4] Although the PUB did not specify the long Canada yield in its decision, the range of 4.50-4.65% represents the range of forecasts for 2007/08 provided by the experts in this proceeding.

2. Benchmark Return on Equity for Test Years 2008-2010

Expert testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Preparation of testimony, responses to information requests and cross-examination of witnesses entail a considerable amount of money, time and effort. As a result, the cost impact on a utility the size of NUNWT can be significant. Since the PUB recently undertook a comprehensive review of the return on equity and detailed its findings in a decision released less than six months ago, NUNWT is prepared to accept the PUB's benchmark return on equity as a point of departure for establishing its allowed return on equity for the 2008-2010 test years, as adjusted for changes in interest rates. By using the benchmark return on equity established in Decision 13-2007 as a point of departure, the costs associated with the determination of the allowed return on equity for NUNWT should be greatly reduced. The cost of capital testimony can then focus on the issue of capital structure that is required to fully compensate for the utility's risks and, if necessary, given the specific financing considerations of the utility, any incremental equity risk premium relative to the benchmark return on equity that is required.

Given these considerations, I accept, for the express purposes of this proceeding, that the benchmark return on equity determined by the PUB in Decision 13-2007, as adjusted for changes in interest rates since the decision was issued, will be used as the basis for establishing the allowed return on equity for NUNWT.[5] That return on equity, however, can only be applied to a common equity ratio that fully compensates for NUNWT's business risks.

To adjust the benchmark return on equity established in Decision 13-2007 for changes in interest rates, an automatic adjustment mechanism can be used. Automatic adjustment mechanisms for determining a utility's allowed return on equity are relied upon in six different regulatory jurisdictions in Canada. The various mechanisms are all quite

[5] In my opinion, the benchmark return on equity established in Decision 13-2007 is below the level commensurate with the comparable returns standard.

similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a base, or initial, return on equity and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base allowed return on equity are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula, or adjustment factor, to be used to adjust the allowed return on equity from one year to the next. The forecast yield on the long-term Government of Canada bond is used as the proxy for the risk-free rate.

Application of an adjustment mechanism like those used in most Canadian jurisdictions requires the following steps:

Step 1: Establish the forecast long-term Canada bond yield for the test year(s),

Step 2: Apply the adjustment factor to the difference between the test year forecast(s) of the long-term Canada bond yield and the bond yield underlying the base allowed return on equity, and

Step 3: Adjust the base allowed return on equity by the amount(s) determined in Step 2.

In five of the six Canadian jurisdictions that currently use an automatic adjustment mechanism,[6] the adjustment factor is set at 0.75, i.e., the change in allowed return on equity equals 75% of the change in the forecast long-term Government of Canada bond yield. In my opinion, a 75 basis point change in allowed return on equity for every one percentage point in the forecast long term Government of Canada bond yield is a reasonable approximation of the relationship between the cost of equity and interest rates.

[6] The five regulatory boards that use automatic adjustment mechanisms with a 0.75 adjustment factor are the Alberta Energy and Utilities Board, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board, and the Régie de l'Energie de Québec. In Newfoundland and Labrador, the adjustment factor is 0.80.

As indicated in Section II.C.1 above, a benchmark return on equity of 8.75% (at a long-term Canada bond yield of 4.50-4.65%) can be inferred from the PUB's 2007/08 allowed return on equity for NTPC. NUNWT is proposing rates for a three-year test period, 2008-2010. I recommend that the PUB adopt a single return on equity for the three test years, based on the average forecast long-term Government of Canada bond yield during the three test years.

Consensus Economics, *Consensus Forecasts* (October 2007) anticipates the following 10-year Government of Canada bond yields:

Table 1

January 2008	October 2008	2008[1/]	2009	2010
4.4%	4.7%	4.55%	5.1%	5.1%

1/ Average of the January and October 2008 forecasts.

The average forecast 10-year Government of Canada bond yield for 2008-2010 is 4.95%.[7]

The yield curve at the end of October 2007 was relatively flat; the spread between the 10 year and the long-term Canada bond yields was seven basis points. The addition of a spread of seven basis points to the average 2008-2010 10-year Canada bond yield forecast of 4.95% results in a forecast long-term Canada bond yield of just over 5.0%. While the three year average forecast long-term Canada bond yield of 5.0% is somewhat higher than the forecast for 2008 alone, NUNWT is taking the risk that the actual long-term yields in 2009 and 2010 will be higher than currently anticipated.[8]

[7] The five Canadian regulatory boards that use a 0.75 adjustment factor referenced in footnote 6 also all rely on *Consensus Forecasts*' outlook for 10-year Canada bond yields, from which they then derive a forecast of the long-term Government of Canada bond yield. There is no consensus forecast of the long-term Canada bond yield.

[8] On average, historically, the spread between 10-and 30-year Canada bond yields has been 30 basis points. If the yield curve reverts to a more normal upward slope over the test period, even if the 10-year Canada

Based on a 5.0% long-term Canada bond yield forecast, the benchmark return on equity (ROE) for NUNWT's 2008-2010 test years is calculated as follows:

Benchmark $ROE_{5\%}$ = Benchmark $ROE_{Initial}$ + Adjustment Factor x ($Current_{BY}$ – $Initial_{BY}$)
Benchmark $ROE_{5\%}$ = 8.75% + 0.75 * (5.0% – 4.6%)
Benchmark $ROE_{5\%}$ = 9.1%

I recommend, therefore, that a benchmark return on equity of 9.1% be adopted for all three test years; the 9.1% would be applicable to the common equity ratio estimated in Sections III to VIII. If, however, the common equity ratio adopted for ratemaking purposes is lower than that which would fully compensate for NUNWT's business risks, then an upward adjustment will need to be made to the benchmark ROE for NUNWT's higher financial risks.

III. PRINCIPLES FOR CAPITAL STRUCTURE

The following principles should be respected when establishing the appropriate capital structure for NUNWT:

A. The Stand-Alone Principle.
B. Compatibility of Capital Structure with Business Risks.
C. Maintenance of Creditworthiness/Financial Integrity.

Each of these principles is defined below.

bond yield forecasts during 2009-2010 turn out exactly as currently anticipated, long term Canada bond yields will be higher than the forecast.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by NUNWT should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

NUNWT is 76% owned by ATCO Electric with the remaining 24% owned by Denendeh Investments Limited Partnership (14%) and Arctic Energy Investors Group (10%). ATCO Electric, in turn, is a wholly-owned subsidiary of CU Inc. NUNWT operates as a stand-alone entity (separate from the other electric utility operations of ATCO Electric). CU Inc. raises debt on behalf of NUNWT. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities, including NUNWT, at the cost incurred by CU Inc. NUNWT's customers receive the benefits of those ratings. In turn, NUNWT should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the benefits of debt costs that reflect an A(high)/A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

Based on the indicated spreads for new issues as published by RBC Capital Markets, CU Inc. has been able to raise new 30-year debt on average at approximately 110 basis points over a similar term Government of Canada bond during 2007. Spreads for utilities with one debt rating in the BBB category (split-rated utilities) have ranged from 122 basis points (Union Gas rated A by DBRS and BBB+ by S&P) to 155 basis points (EPCOR Utilities, rated A(low) by DBRS and BBB+ by S&P) and have averaged approximately 135-140 basis points (See Schedule 1).

The 2007 average masks the widening spreads during the year. As investors have become more risk-averse during the year, and the outlook for the economy has deteriorated, credit spreads have widened since the end of 2006. At the end of November 2007, the indicated spread for a new 30-year CU Inc. issue was 130 basis points versus 95 basis points a year earlier. Spreads for new split-rated A/BBB issues have increased from approximately 125-130 basis points to 165 basis points over the same period.

Depending on the state of the capital markets, the spread between the cost of a new long-term debt issue for a strong A credit and one for a split A/BBB credit can be much higher than it is currently. Within the past five years, the spread has been as high as 100 basis points.

With respect to electric power corporations that are still investment grade but rated in the BBB category by all the debt rating agencies, there is only one conventional equity corporation (i.e., non-income trust) included in the S&P/TSX Utilities Sector, TransAlta Corporation. The average indicated spread for a new 30-year TransAlta Corporation debt issue during 2007 has been 250 basis points; at the end of November 2007, the spread was 325 basis points. (Schedule 1) The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long term debt of approximately 195 basis points provides a perspective on the potential magnitude of the benefits to ratepayers of NUNWT's affiliation with CU Inc. As a true stand-alone entity, NUNWT would not be able to obtain investment grade debt ratings given its small size. The estimation of an appropriate capital structure for NUNWT should recognize the magnitude of the cost benefits conferred upon ratepayers arising from NUNWT's ability to access debt capital through CU Inc. rather than on its own.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

For larger utilities like CU Inc. which regularly access the public debt markets, a reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult or weak capital market conditions.

As noted above, NUNWT is too small to have its own debt ratings (i.e., it would not be investment grade) or to access the public debt markets on its own. If it were to access third-party debt on its own, its options would be limited to banks or insurance companies at a significantly higher cost than is available to CU Inc., and with more stringent covenants. A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to NUNWT both the actual cost of debt that NUNWT would be able to obtain on its own and the capital structure that would be required by a potential lender to provide debt capital in the absence of its affiliation with CU Inc. (that is, for example, if its sole equity shareholders were the Denendeh Investments Limited Partnership and Arctic Energy Investors Group).

To my knowledge, the only small (total capital less than $100 million) regulated company that has accessed debt on a true stand-alone basis within the past five years is Natural Resource Gas (NRG), a small Ontario natural gas distributor. NRG was able to obtain five-year bank financing during 2005, a period of easy credit, at a spread over five-year Government of Canada bond yields of approximately 280 basis points. At the same time, the larger gas utilities (with debt ratings in the A/BBB rating categories) were able to issue five-year debt at spreads of 40-45 basis points over five-year Government of Canada bond yields. At the time, TransAlta Corporation was able to raise five-year debt at approximately 70 basis points above a similar term Government of Canada bond yield. NRG is of similar size to NUNWT (assets of approximately $9 million), but of somewhat lower business risk. Nevertheless, NRG's stand-alone cost of debt provides a further indicator of the order of magnitude of the benefit that NUNWT's ratepayers receive as a result of NUNWT's affiliation with CU Inc.

My assessment of the appropriate capital structure for NUNWT balances the stand-alone and creditworthiness and financial integrity principles with a recognition that the impact of small size on lenders' willingness to lend funds and on the stand-alone cost of debt would be, in part, related to the lack of liquidity and institutional interest in small debt issues rather than to fundamental business risk factors. Nevertheless, the appropriate capital structure and return on rate base for NUNWT needs to recognize the cost benefits that NUNWT's ratepayers receive.

IV. BUSINESS RISK

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short-term and long-term risks. Long-term risks are important because utility assets are long-lived. Moreover, utility stocks are not typically purchased as short-term investments. Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall higher return rewards when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future.

Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

Market demand risk relates to those factors that can lead to annual volatility in electricity sales or loss of customers. It includes market size, economic diversity and strength of the service area, growth potential, concentration of sales, competition with alternative energy sources and weather.

Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity. The physical risks of the utility are a function of its geography, mix of generation and ability to access alternative sources of supply.

The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

NUNWT is a very small integrated electric utility serving approximately 2,600 customers in eight communities in the south central portion of the Northwest Territories. The largest community served is the Town of Hay River, with a population of 3,650. The populations of the other communities range from approximately 50 to 725. Total sales are approximately 35 GW.h. To put this in perspective, the following table compares customers, sales, and rate base of major Canadian investor-owned and government-owned electric utilities with rated debt, i.e., not guaranteed.

Table 2

Company	Customers	Sales (GW.h.)	Rate Base ($ Millions)
NUNWT	2,600	35	12
Electric Utilities with Rated Debt:			
ATCO Electric	216,000	10,300	1,500
EPCOR Utilities	318,000	7,100	500
FortisAlberta	430,000	14,700	800
FortisBC	152,000[1/]	3,100	680
Hydro One	1,300,000	29,300	8,400
Hydro Ottawa	280,000	7,500	500
Maritime Electric	66,000	1,000	200
Newfoundland Power	229,500	5,000	750
Nova Scotia Power	460,000	11,600	2,900

[1/] Includes both direct (approximately 100,000) and indirect customers.

As the table above indicates, NUNWT is approximately one-sixteenth the size of the smallest utility (Maritime Electric) with its own debt ratings. From a business risk fundamentals perspective, small size limits a utility's ability to diversify its risks geographically, operationally and among services provided.

NUNWT has franchise agreements to serve its communities which must be renegotiated periodically. The majority of the existing agreements expire within three years; the franchise to serve the largest community, the Town of Hay River, expires in 2010. The risk of franchise non-renewal is relatively higher for NUNWT than many other electric utilities because of the proximity of Northwest Territories Power Corporation (NTPC).

NUNWT's customer profile, based on 2007 actual data, is as follows:

Table 3

	Residential	General Service	Street & Sentinel Lighting
Sales ($000)	3,716	4,438	264
Customers	1,979	631	na

While NUNWT currently has no industrial customers of its own,[9] the economic base of the Northwest Territories (NWT) will have secondary impacts on the residential and commercial customer load. The NWT's industrial base is dominated by a single volatile industry, diamond mining, accounting for approximately half of GDP in 2006. The risks associated with diamond mining include world-wide supply and demand, the latter being tied to the availability of discretionary income globally, the uncertainty associated with the forecast versus actual reserves, including the quality of those reserves, the impact of currency fluctuations on both costs and revenues, the impact of higher than expected costs of exploration, development and production, and the potential impact of changes in environmental standards and social policies. Diamond mining in the NWT comprises the additional risk associated with the impacts of climate on the ability to operate and the costs of operation.[10] The fortunes of the diamond mining industry will impact in-migration and out-migration as well as the fortunes of commercial enterprises that have developed either in direct support of the industry (e.g., diamond cutting and polishing) or indirect support of the recent growth in population.

Partly offsetting the potential volatility of the diamond mining industry is the stabilizing impact of government-related load (e.g., schools, municipal government offices). Government-related load contributes a degree of stability to NUNWT's overall revenues, as government-related load is less likely to be impacted by economic swings than other customer groups.

The NWT has experienced large variations in GDP growth over the past few years, largely due to the diamond mining sector. In 2003, the NWT experienced the highest level of economic growth in the country (13.4% versus 1.9% for Canada), with the

[9] NUNWT has been approached by Tamerlane Ventures, a zinc-lead mining company, to provide service to the Pine Point mine site commencing in 2008. Tamerlane's power requirements would increase NUNWT's sales (in GWhrs) by 50%. My assessment of the business risks of NUNWT is premised on the assumption that any arrangement between Tamerlane and NUNWT would not impose any additional business risks on NUNWT.

[10] Jericho Diamond Mine located in Nunavut, the most recently opened (March 2007) mine, reported a 3rd Quarter 2007 asset impairment charge, arising from ongoing operational and production issues, the appreciation of the Canadian dollar and rising input costs. The company (Tahera Diamond Corporation) reported that a shortage of funds it was forced to defer its scheduled debt repayments.

opening of a second diamond mine. Economic growth remained relatively strong in 2004, increasing 3.6% (versus Canada's 3.1%). However, in 2005, the NWT's economic growth turned negative as both the value and production of the diamond industry declined, largely due to the appreciation of the Canadian dollar and the processing of lower grade ore. The reduction in mining value and output resulted in territorial growth contracting 2.5%, the lowest rate of growth in the nation. In 2006, economic growth rebounded to 2.9%, approximately the same rate of growth as for all of Canada (2.8%).[11] The widely divergent rates of annual growth demonstrate the potential volatility in the economy.

Not only do the actual rates of growth exhibit considerable volatility, there can be significant differences between the forecast and the actual rates of growth. For example, in February 2007, the Government of the Northwest Territories, in its *2007-2010 Business Plans* forecast a 2006 rate of real GDP growth of approximately 8%. The actual rate, as indicated above, was only 2.8%. The potential variance between forecast and actual rates of growth enhances NUNWT's forecasting risk. On the cost side, forecasting risks are further increased by the tight labour market, particularly for skilled workers, rising wages and rising costs of basic materials.

Electric utilities, including NUNWT, are subject to the risk of lost sales arising from the increasing emphasis on energy efficiency, conservation and reducing peak load. Lost load due to energy efficiency and conservation efforts reduces the utility's earnings. The GNWT's *Energy for the Future: An Energy Plan for the Northwest Territories*, released in March 2007, emphasizes the implementation of energy conservation and efficiency initiatives, with the objective of reducing energy costs and environmental impacts.[12]

With respect to supply and physical risks, NUNWT faces a significantly higher level of risk relative to other Canadian electrical utilities. NUNWT's service area is comprised of

[11] Statistics Canada, *The Daily, Provincial and Territorial Economic Accounts*, November 8, 2007.
[12] A number of regulatory jurisdictions in North America have implemented or are investigating revenue decoupling (decoupling revenues from consumption) to address this issue.

multiple communities which are unconnected by a single system grid, which prevents them from accessing alternative sources of power. In Hay River, the company purchases power from NTPC's Talston hydroelectric system and maintains a back-up diesel generation plant. In the smaller, more remote communities, NUNWT both generates and distributes power.

Approximately 28% of NUNWT's rate base is comprised of diesel generation assets. The presence of generation assets in rate base increases the business risk of NUNWT relative to a pure distribution utility, as the operational risks associated with generation exceed those of "wires" operations. In the case of NUNWT, the operating risks are exacerbated by the severe climate in which the utility operates, both in terms of the risk of outages and the potential unanticipated impacts of repair, both in terms of time and expenditures. While NUNWT has deferral accounts for diesel fuel costs, the high cost of diesel fuel creates an additional incentive to conserve energy (thus leading to lower than expected sales). Further, in contrast to hydroelectric generation, diesel generation is exposed to greater risks of complying with increasingly stringent environmental standards.

With respect to regulatory risk, as independent tribunals, regulators have the power to expose utilities to relatively high risks, by, for example, disallowing costs, approving rate designs that are tilted against recovery of fixed costs, or returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility an opportunity to achieve a fair return with a reasonably high probability. This explains why regulation is considered to be a key element of a utility's business risk profile. On balance, the regulatory environment in the NWT has been even-handed and reasonable in its approach. The Board has granted deferral accounts for costs that are beyond the control of management, including power costs, diesel fuel and generation costs, plant maintenance expense and rate case expense.[13] Nevertheless regulatory decisions can also have a negative impact on utilities.

In the recent NTPC decision, the Board required NTPC to refund to customers amounts related to brushing costs that had been forecast by NTPC for earlier test years but not spent. While this action arguably constituted retroactive ratemaking, the Board recently vacated that direction, following a review of the decision.

On balance, as a very small utility operating in a service territory with an undiversified economic base tied to a single industry and facing significant geographic physical/operating challenges, NUNWT:

- is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada,
- is of higher than average business risk within the spectrum of Canadian utilities and,
- is of higher business risk than its sister utility in the NWT, Northland Utilities (Yellowknife) Inc.[14]

In light of the PUB's stated preference in Decision 13-2007, I have estimated the capital structure for NUNWT that would compensate for NUNWT's higher business risk in Sections V to VIII below.

[13] The existence of these deferral accounts does not constitute a guarantee that the costs accrued in the account will be recoverable from customers.
[14] An analysis of the business risks of Northland Utilities (Yellowknife) Inc. is found in the Return on Rate Base Section of the NUY GRA filing.

V. CAPITAL STRUCTURES OF PEERS

The determination of the capital structure that reflects NUNWT's business risks and would be compatible with the application of the benchmark return on equity requires comparisons with the capital structures of other electric utilities for two reasons. First, electric utilities which raise debt in the public markets (and, therefore, have debt ratings) have capital structures that have been "tested" by the capital markets. Thus, their capital structures, in conjunction with other key financial metrics (e.g., coverage ratios), provide an indication of the capital structure required to maintain investment grade debt ratings. Second, the common equity ratios allowed for other electric utilities (whether or not their debt is rated), either through regulatory decisions or settlements, provide a measure of the level that is warranted for an electric utility to compete for capital with its peers, with due regard to differences in business risk.

Table 4 below sets out the average actual common equity ratios of Canadian electric utilities with rated debt, as well as those of low risk U.S. electric utilities with debt rated in the A category.

Table 4

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	43.4%
Transmission & Distribution	A/Baa1/A-	44.5%
Integrated	A(low)/Baa2/BBB+	40.5%
U.S. A-rated Electric Utilities	na/A2/A	49.0%

Source: Schedules 2, 3 and 4.

Table 4 indicates that the average actual common equity ratios for all Canadian electric utilities with rated debt and for Canadian transmission and distribution utilities have averaged close to 43.5% and just below 45% respectively. The corresponding debt ratings by all three debt rating agencies have been, on average, approximately A-/A(low). Given NUNWT's higher than average business risks, the equity ratios maintained by other Canadian electric utilities indicate that a 45% common equity ratio would be too low to fully compensate for its business risks. Maritime Electric, the smallest of the rated investor-owned utilities, and the one that would be considered the closest comparator of NUNWT, has a target actual common equity ratio of 45%. While it is the closest comparator, it is significantly larger and faces lower business risk than NUNWT. Moreover, its allowed return on common equity has been materially higher than the PUB's benchmark return on equity.[15] The comparison with Maritime Electric strengthens the conclusion that a 45% common equity ratio (at the benchmark return on equity) is well below the level required to fully compensate for NUNWT's business risks. With respect to other utilities regulated by this Board, for the 2007/08 test year, the PUB adopted a common equity ratio of 48.86% and an incremental equity risk premium of 0.50% for NTPC, which faces somewhat higher business risk than NUNWT. The corresponding equity ratio for NTPC that would fully compensate for its higher business risks would be approximately 56-57%. Since NTPC faces somewhat higher business risk than NUNWT, the fully compensatory equity ratio for NUNWT indicated by the Board's decision would be slightly lower than 56-57%.

As the capital market has become increasingly global, Canadian utilities increasingly find themselves competing with foreign utilities for financing. The similarities and proximity of the U.S. and Canadian capital markets make comparisons with U.S. electric utilities especially relevant. The major bond rating agencies increasingly draw comparisons between Canadian utilities and their U.S. peers. Thus, the capital structures of U.S. electric utilities of reasonably similar business risk to NUNWT and with debt rated in the A category may provide some guidance.

[15] Maritime Electric serves the relatively sparsely populated Prince Edward Island, is dependent upon New Brunswick Power for the majority of its power supply, but also has approximately 27.5% of its net property, plant and equipment assets invested in generation. Maritime Electric, which is not subject to an automatic adjustment formula, was allowed a common equity return of 10.25% for the 2006 test year. By comparison, the EUB generic return on equity for 2006 was 8.93%. The difference of approximately 1.25% in ROE is equivalent to approximately 15-20 percentage points in equity ratio.

Since 1999, S&P has assigned to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest.[16] As of November 2007, the median business profile score of the U.S. electric utilities with debt rated in the A category was "4". By comparison, the average S&P business profile score assigned to Canadian utilities has been "3". The majority of these companies are largely "wires" or "pipes" companies. While NUNWT is primarily a "wires" utility, as previously discussed, it also has a significant generation component of rate base.[17] As discussed in Section IV, NUNWT would be viewed as facing higher business risks than the typical Canadian utility. On balance, based on its business risk fundamentals, NUNWT would, on a stand-alone basis, be assigned a business profile score of no less than "4", which is higher than the score assigned to the typical Canadian utility, but the same category as the A rated U.S. utilities. Given it extremely small size, the stand-alone business profile score could be as high as "5", that is, equivalent to an average risk utility.

The higher business risk of the A-rated U.S. electric utilities relative to the typical Canadian electric utility is partly reflected in higher common equity ratios. As indicated in Table 4 above, the median 2006 actual common equity ratio of U.S. electric utilities with debt rated in the A category was 49.0%. Given the considerably smaller size of NUNWT relative to the A rated U.S. electric utilities, the U.S. electric utilities' 49% median equity ratio, in isolation, would be a conservative benchmark for NUNWT. Moreover, as discussed in more detail in Section VII, the debt ratings of utilities in a particular business risk category are not solely driven by capital structures. They are also driven by other financial parameters, including coverage ratios. Coverage ratios are a function of cash flows, which, in turn, are dependent upon equity returns. The common equity return for the A rated U.S. electric utilities over the past three years (2004-2006) has averaged 11.8% (see Schedule 2), compared to the 9.1% benchmark return on equity

[16] The key qualitative factors that S&P evaluates in assessing the business risk of regulated electric utilities include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness.

[17] Newfoundland Power, for example, was assigned a business risk profile score of "3". Newfoundland Power would be considered to face lower business risks than NUNWT, given its size, service area, more comprehensive slate of deferral accounts, including revenue protection against weather variations, and smaller generation component of rate base.

relied upon in this analysis, a difference of close to 1.75 percentage points. Given the similarity in the level of business risk between NUNWT and the A rated U.S. electric utilities, the considerable higher ROE of the A rated U.S. electric utilities relative to the benchmark ROE supports the conclusion that a 50% common equity ratio would be too low to equate NUNWT to a benchmark utility.

With respect to allowed common equity ratios, Table 5 below summarizes the most recently adopted capital structures for major Canadian electric utilities, along with any applicable incremental equity risk premiums. Unlike NUNWT, both NTPC and Yukon Energy are government-owned utilities whose debt is guaranteed by their respective Territorial governments. However, like NUNWT, they are both northern utilities, and they are both largely treated like investor-owned utilities for purposes of establishing capital structure and return on equity.[18]

Table 5

Alberta Taxable Distributors	37.0%
FortisBC	40.0% (plus 0.40% risk premium above BCUC's low risk utility benchmark)
Maritime Electric	42.7% (ROE has been approximately 1.25% higher than Canadian average)
Newfoundland Power	44.5% (risk premium 0.15% higher than benchmark)
Northwest Territories Power	48.6% (plus 0.50% risk premium)
Nova Scotia Power	37.5% (ROE approximately 0.75% higher than Canadian average)
Ontario Electric Distributors	40.0%
Yukon Energy	40.0% (plus 0.52% risk premium above BCUC's low risk utility benchmark) [1/]

[1/] Equal to average of the incremental equity risk premiums of Pacific Northern Gas (65 basis points) and FortisBC (40 basis points); by Order in Council, Yukon Energy's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Schedule 5.

[18] Yukon Electrical Company Limited, an investor-owned northern electric utility and affiliate of NUNWT, has not had its capital structure reviewed by the Yukon Utilities Board since the 1993/1994 test years.

If the capital structure for each of the utilities in Table 5 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47%. Since NUNWT would be of higher business risk than the average of the utilities in Table 5, the 46-47% indicated common equity ratio is lower than the level required to fully compensate NUNWT for its higher business risks.

With respect to U.S. electric utilities, since the beginning of 2005, the average common equity ratio adopted for ratemaking purposes has been 47.4%.[19] The average business profile score of all U.S. electric utilities rated by S&P is "5". Thus, the U.S. electric utility industry as a whole is of similar to or slightly higher business risk than NUNWT. However, the average debt rating of all U.S. electric utilities is only BBB. Consequently, it may be inferred that a common equity ratio of 47.5% is not adequate for a "5" business profile score and an A credit rating. Given NUNWT's similar to somewhat lower business risks than the U.S. electric utility industry in the aggregate, but higher target debt rating (in the A category), the U.S. electric industry average allowed common equity ratio of 47.5% would be below the bottom end of equity ratios required to equate NUNWT to the benchmark utility.

On balance, the actual and allowed equity ratios of other Canadian utilities, and those of U.S. electric utilities (in conjunction with their actual and allowed ROEs), indicate that the required common equity ratio for NUNWT is no less than 50%.

[19] Regulatory Research Associates, *Major Rate Case Decisions, January – September 2007*, October 3, 2007. Allowed returns on equity have averaged 10.4% over the same period.

VI. RATING AGENCY DEBT RATIO GUIDELINES

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), S&P has published the most detailed matrix of quantitative guidelines for different debt ratings.[20] For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds From Operations (FFO[21]) Interest Coverage, and FFO To Total Debt (discussed in Section VII). S&P does not apply their guidelines mechanistically; however, the guidelines do represent one objective basis for evaluating an appropriate stand-alone capital structure for NUNWT.

S&P's debt ratio guidelines for an A debt rating and a business risk scores of "4" and "5", the range of notional business risk scores attributed to NUNWT, are as follows:

Table 6

	"4"	"5"
Total Debt/Total Capital	45.0-52.0%	42.0-50.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

The guidelines for business risk profile scores of "4" and "5" indicate that a common equity ratio in the range of 48% to 58% (mid-range of 50-55%) is warranted for an A rating.

Moody's also has published quantitative guidelines. As with S&P, other factors may outweigh the mechanistic application of the guidelines in determining a rating. However, the guidelines provide "broad guidance on the ratio ranges that may generally be seen at different rating levels".[22] While neither NUNWT nor CU Inc. has a Moody's rating,

[20] DBRS has published guidelines, but the guidelines do not distinguish by either business risk or investment grade rating category.
[21] FFO means Funds from Operations, which equal net income plus non-cash items, including depreciation, deferred taxes and other non-cash expenses, e.g., amortization of regulatory assets.
[22] Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005, page 8.

there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's. Thus Moody's guidelines are applicable to those companies and, in turn, will play a role in the formation of target capital structures among Canadian utilities, with the objective of maintaining investment grade debt ratios.

Canadian distribution utilities are typically considered to be operating in a "low business risk" environment by Moody's due to the high degree of regulation and a supportive regulatory system. However, due to its specific business risk fundamentals and small size, NUNWT would likely be classified as a "medium business risk" utility. Moody's debt ratio guidelines for an A rating for a regulated company of "medium risk" are:

Table 7

Debt/Capital	40.0-60.0%

Source: Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

Based on Moody's guidelines, which indicate an equity ratio of 40-60% for a medium risk company and an A rating, a reasonable common equity ratio for NUNWT compatible with a stand-alone A rating would be in the upper half the range, i.e., approximately 50-60%.

The S&P and Moody's debt ratio guidelines, taken together, support a common equity ratio of approximately 50-60% (mid-point of 55%).

VII. RATING AGENCY GUIDELINES OTHER THAN DEBT RATIO

Based on the actual and allowed equity ratios for other Canadian and low risk U.S. electric utilities (Section V), the rating agency debt ratio guidelines (Section VI) and in consideration of NUNWT's relative business risk (Section IV), a common equity ratio range of 50-55% (mid-point of 52.5%) would be required to equate NUNWT to the benchmark utilities (i.e., one with a credit rating of A).

However, the common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Both S&P and Moody's consider cash flow coverage ratios to be key quantitative financial metrics, specifically FFO Interest Coverage and FFO/Total Debt. If a utility is able to achieve adequate cash flow coverage ratios, despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of return on equity, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's and Moody's guideline ranges for the debt ratio, while an important indicator of an appropriate capital structure, should be referenced with regard to other financial metrics.

Table 8

	S&P		**Moody's**
	"4"	"5"	"Medium Risk"
FFO Interest Coverage	3.5-4.2X	3.8-4.5X	3.5-6.0X
FFO/Average Total Debt	20.0-28.0%	22.0-30.0%	22.0-30.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006 and Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

I have estimated the FFO Interest Coverage and FFO/Total Debt ratios for NUNWT based on common equity ratios of 50.0% and 55.0%. Specifically, I estimated the ratios using capital structures containing 50.0% and 55.0% equity, each in conjunction with a benchmark return on equity of 9.1%, NUNWT's forecast embedded cost of debt of 6.5% and forecast depreciation expense for 2009. In interpreting the results, it is important to recognize, as noted earlier, that the guidelines are not applied mechanistically.

NUNWT's indicated FFO Interest Coverage ratios are 4.6X and 5.2X at 50.0% and 55.0% equity respectively. The indicated ratios are above the upper end of S&P's guideline ranges of 3.5X to 4.5X for business risk profile scores of "4" and "5" and an A rating. At a 50% equity ratio, the indicated FFO interest coverage is lower than the mid-point of the Moody's guideline range (4.75%), but approximately at the mid-point of the upper half of the range at a 55% equity ratio. The estimated FFO/Total Debt ratios (23.0% and 27.0% at common equity ratios of 50.0% and 55.0% respectively) are within S&P's 20-30% range, as well as within Moody's range. Table 9 (below) indicates that FFO Interest Coverage ratios for NUNWT of 4.6X and 5.2X would be higher than the achieved ratios of other Canadian electric utilities (3.5X). However, the average FFO coverage ratio achieved by the low risk (A rated) U.S. electric utilities (4.9X) is in the middle of the range of FFO coverage ratios estimated for NUNWT at 50.0% and 55.0% equity ratios. Given NUNWT's higher business risks relative to an average risk Canadian utility, it should be expected that the FFO interest coverage ratio would be higher.

As shown in Table 9, the FFO/Total Debt ratios for NUNWT of 23% to 27% would be higher than the achieved FFO/Total Debt ratios of other Canadian and low risk U.S. electric utilities.

Table 9

Electric Utilities With Rated Debt	Ratings DBRS/Moody's/S&P	FFO Interest Coverage (2004-2006)	FFO to Total Debt (2004-2006)
Canadian Electric Utilities:			
All	A/Baa1/A-	3.5X	17.5%
Transmission & Distribution	A/Baa1/A-	3.8X	17.5%
Integrated	A(low)/Baa2/BBB+	3.3X	14.2%
U.S. A-rated Electric	na/A2/A	4.9X	22.3%

Source: Schedules 2 and 3.

Although S&P no longer publishes a guideline range for pre-tax (or EBIT)[23] interest coverage ratios, it is still considered an important quantitative financial ratio by all three debt rating agencies (S&P, DBRS and Moody's). It has also been a key ratio considered by regulators (e.g., EUB and BCUC) in assessing capital structures. Moreover, in contrast to the FFO coverages, which are driven in part by depreciation expense, EBIT coverage is more a function of capital structure and return on equity.

S&P's most recent EBIT interest coverage guideline range for an A rating at "4" and "5" business profile scores was 3.3X to 4.3X (mid-point of 3.8X). [24] At common equity ratios of 50% and 55%, the benchmark return on equity of 9.1%, NUNWT's embedded debt cost of 6.5%, and an income tax rate of 29.5%,[25] NUNWT's EBIT interest coverage would be in the range of approximately 3.0X to 3.4X. Table 10 below demonstrates the calculation of the EBIT interest coverage at a 52.5% common equity ratio.

[23] Earnings before Interest and Taxes.

[24] S&P, *Utilities and Perspectives*, June 1999. The EBIT interest coverage guideline ranges were excluded from the quantitative guidelines after June 2004, but the actual EBIT interest coverage ratios continue to be provided in the annual utilities' *CreditStats* published by S&P.

[25] Statutory combined Federal (18%) and Northwest Territories (11.5%) rate as of 2010.

Table 10

	Cost Rate	Percentage	Weighted Component
	(1)	(2)	(3)=(1)*(2)
Debt	6.51	47.5%	3.09
Common Equity	9.10	52.5%	4.78
Tax Rate (t)	29.5%		
Income Tax = 4.78*(t/(1-t)			2.00
Pre-Tax Return			9.87
EBIT Interest Coverage[1/]			3.2X

[1/] EBIT Interest Coverage = Pre-Tax Return ÷ Weighted Debt Component.

The indicated EBIT interest coverage ratio of 3.0X at a common equity of 50% is below the bottom end of S&P's guideline range; an EBIT coverage ratio of 3.4 times at a 55% ratio is marginally above the lower end of the range.

Table 11 below indicates that an EBIT interest coverage ratio in the range of 3.0 to 3.4 times would be higher than the average for the other Canadian electric utilities. Over the period 2004-2006, the average EBIT coverage ratios for all major Canadian electric utilities were 2.7X. In light of its higher than average business risk, an EBIT interest coverage ratio for NUNWT of 3.0-3.4X would be reasonable relative to the achieved ratios of other Canadian electric utilities. An EBIT coverage ratio of 3.4 times, however, would still be lower than the 3.6X EBIT interest coverage ratio achieved by low risk (A rated) U.S. electric utilities, which is partly attributable to the U.S. utilities' higher achieved returns on equity (11.8%), relative to the 9.1% benchmark return on equity.

Table 11

Electric Utilities With Rated Debt	Ratings DBRS/Moody's/S&P	EBIT Interest Coverage (2004-2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	2.7X
Transmission & Distribution	A/Baa1/A-	2.5X
Integrated	A(low)/Baa2/BBB+	2.6X
U.S. A-rated Electric	na/A2/A	3.6X

Source: Schedules 2 and 3.

In summary, my estimates of the various financial metrics for NUNWT, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, provide support for a common equity ratio at the upper end of a range of 50-55%, consistent with the mid-point of the S&P/Moody's guideline ranges for capital structure.

VIII. DEBT RATING AGENCY COMMENTARY

As indicated in Sections VI and VII above, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a utility. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity base on which it is allowed to earn, but also the allowed return on equity and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S. The investment community has also indicated to the National Energy Board that it believes the financial parameters adopted for regulated companies are too low.[26]

[26] National Energy Board, *Canadian Hydrocarbon Transportation System*, August 2005, June 2006 and July 2007.

DBRS

DBRS has commented generally on the relatively low common equity ratios and returns that are being allowed in Canada. In a May 2003 commentary, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, DBRS noted that it would like to see both the deemed common equity ratios increased as well as increases in allowed returns to levels more consistent with U.S. returns.

In December 2004, subsequent to the EUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity ratios and equity returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[27] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.[28]

[27] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The ROE of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower ROE is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

[28] Other DBRS reports have referenced the low approved returns on equity as a "challenge" for Canadian utilities, i.e., ATCO Ltd. (January 2007), CU Inc. (January 2007), Union Gas (March 2007) and FortisAlberta (May 2007).

<u>Standard and Poor's</u>

With respect to S&P, in early March 2003, the debt rating agency announced that it was reevaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation). S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

Like DBRS, S&P has made references to the low deemed equity ratios and equity returns allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. For example, S&P commented on the thin equity layers (and the low equity returns) allowed the ATCO group of utilities after the EUB decision, stating,

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004)

In a more recent report for NUNWT's parent, CU Inc. (rated A), S&P stated in reference to the company's businesses in Alberta,

> Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities (S&P, *CU Inc.*, October 26, 2007)

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[29] As indicated above, the "aggressive leverage" is largely a result of regulatory directives.

[29] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

In sum, the debt rating agencies consider the allowed common equity ratios for Canadian utilities to be relatively thin and the allowed ROEs to be relatively low. (Actual equity ratios will generally track allowed equity ratios, as utilities have no incentive to maintain higher equity ratios than allowed by the regulator for ratemaking purposes.)

Based on the views of the debt rating agencies, in the aggregate, the allowed and actual common equity ratios of other Canadian electric utilities would be on the low side as a point of departure for estimating a reasonable capital structure for NUNWT. In that context, the upper end of a 50-55% common equity range would be reasonable for NUNWT and allow the benchmark return on equity to be applied without an incremental equity risk premium.

IX. CHOICE OF CAPITAL STRUCTURE AND RISK PREMIUM

As previously discussed, the Board indicated in Decision 2007-13 that it would prefer to see all of the business risk reflected in the capital structure. In respect of the Board's preference, I have estimated the common equity ratio that would fully compensate for NUNWT's business risk, i.e., the upper end of a range of 50.0% to 55.0%. A common equity ratio of 55.0% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained by NUNWT. To reach an actual common equity ratio of 55.0%, the three shareholders of NUNWT would be required to access additional capital to bring the actual equity ratio up to 55.0% and maintain their proportionate interest.[30]

There are two concerns with this approach. First, while the shareholders are willing to accept the benchmark return on equity as a point of departure for setting the allowed

[30] In principle, the common equity ratio could be simply deemed to be 55% irrespective of NUNWT's actual common equity ratio. This is not without precedent. For example, the Ontario Energy Board has deemed common equity ratios of 40% for all of the electricity distributors under its jurisdiction. The actual equity ratios of the distributors at the end of the 2006 ranged from negative to 100%. However, Canadian regulators generally have been reluctant to adopt deemed common equity ratios that are materially higher than the actual equity ratios that are maintained by the utilities.

return on equity for NUNWT, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in NUNWT (as well as other shareholders) consider the returns that Canadian utilities are allowed to be low begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return. In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities during 2006 and 2007 (through 3rd quarter) has been approximately 10.3%, approximately 1.4 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-12.4%.[31]

Second, in contrast to NUNWT's majority shareholder, the minority shareholders do not have ready access to the equity markets. To raise the additional capital necessary to make the required equity infusion, the principal source of external funds would likely be bank loans. Requiring the minority shareholders to raise debt to make an equity infusion would create an additional level of risk for those shareholders, analogous to purchasing common equity shares on margin. At a benchmark return on equity of 9.1%, the differential between the return on equity that the shareholder has an opportunity (not a guarantee) to earn on his utility investment and the cost of a bank loan is not sufficiently wide to induce the shareholders to accept the additional financial risk that moving the actual equity ratio to 55% would entail.

[31] The Conference Board of Canada, in reference to allowed returns for U.S. electricity transmission, underscored the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled *Electricity Restructuring: Opening Power Markets*, the Conference Board stated,

> 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. 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.

The same conclusions are relevant to distribution and generation.

These considerations lead me to recommend that NUNWT move to an equity ratio of 50.0%, with the difference between a 50% equity ratio and the 55% ratio that would fully compensate for NUNWT's business risks reflected in an incremental equity risk premium. The estimate of the risk premium recognizes that within the five percentage point range of equity ratios (from 50% to 55%), the overall cost of capital would be relatively constant. In other words, as the equity ratio moves from 55% to 50%, the overall cost of capital would not change; the decrease in the equity ratio would be offset by an increase in the common equity return. As demonstrated in Table 12 below, a decrease in the common equity ratio from 55% to 50% increases the equity return from the 9.1% benchmark return on equity to approximately 9.6%.[32]

Table 12

	Proportion	Cost	Weighted Component
Debt	45.0%	6.30%	2.84%
Equity	55.0%	9.10%	5.01%
			7.84%
		Tax Allowance at 29.5%	2.09%
		Pre-Tax Cost of Capital	9.93%
Move Equity Proportion to 50.0%			
Pre-Tax Cost of Capital Remains Unchanged at:			9.93%
Less: Weighted Interest Component (6.3% x 50.0%)			3.15%
Pre-Tax Weighted Equity Component			6.78%
Less: Tax at 29.5%			2.00%
After-Tax Weighted Equity Component			4.78%
ROE at 50.0% Equity			
(After-Tax Weighted Equity Component / 50.0%)			**9.57%**

32 Based on a cost of debt equal to the 5.0% forecast 30-year Long Canada yield plus the November 30, 2007 indicated spread for a new 30-year CU Inc. debt issue of 130 basis points, and the 2010 statutory corporate income tax rate of 29.5%.

The indicated required increase in the common equity return due to the lower equity ratio, and thus the required incremental equity risk premium for NUNWT at a 50% ratio, is approximately 0.50%. A 0.50% incremental equity risk premium results in a recommended ROE for NUNWT of 9.6%.

X. CONCLUSIONS

- In recognition of the PUB's preference to reflect differences in business risk through capital structure alone, I have estimated the capital structure that fully reflects the business risk of NUNWT.

- The return on equity that would be applied to the capital structure that fully compensates for NUNWT's business risk is the Board's benchmark return on equity established in Decision 13-2007, as adjusted for changes in the forecast long-term Canada bond yield.

- I recommend that the Board adopt a single benchmark return on equity for all three test years, 2008-2010, of 9.1%, based on the average forecast of long-term Canada bond yields over the three-year period of 5.0%.

- The capital structure for NUNWT should
    - Respect the stand-alone principle;
    - Be compatible with NUNWT's business risks,
    - Maintain NUNWT's creditworthiness and financial integrity

- NUNWT's business risks are significantly higher than those of the typical Canadian electricity distribution utility, higher than average within the spectrum of Canadian utilities and are higher than its sister utility in the NWT, Northland Utilities (Yellowknife).

- The actual and allowed capital structures of NUNWT's peers, both Canadian and U.S., indicate that, in isolation, the common equity ratio that would equate NUNWT to a benchmark utility would be no less than 50%; taking explicit account of U.S. utilities' considerably higher ROEs relative to the benchmark ROE of 9.1% supports an equity ratio in excess of 50%.

- Debt rating agency guidelines for the debt ratio support a common equity ratio in the range of 50-60%.

- Estimates of the various financial metrics for NUNWT, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for NUNWT should be focused on the upper end of a 50% to 55% range (i.e. at 55%).

- The concerns expressed by the debt rating agencies, as well as other capital market participants, that the common equity ratios of Canadian utilities are too thin (and the ROEs are too low) further support the focus on the upper end of the common equity ratio range for NUNWT of 50% to 55%.

- In sum, the upper end of a 50-55% common equity range would be reasonable for NUNWT and would allow a benchmark return on equity to be applied without an incremental equity risk premium.

- Two factors militate against increasing the actual common equity ratio of NUNWT to 55%:

  (1) The shareholders who would have to raise additional debt capital to effect the change would be exposed to incremental financial risks; and

(2) To require shareholders to commit additional equity capital to have the opportunity to earn an equity return perceived as too low is fundamentally incongruous.

- To address these two factors, I recommend increasing the actual common equity ratio of NUNWT to 50% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 50% equity ratio and the 55% common equity ratio that would fully compensate for the business risks of NUNWT. At a 50% common equity ratio, the allowed ROE for NUNWT should be set at 9.6%.

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 150 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- "Utility Cost of Capital Canada vs. U.S.", presented at the CAMPUT Conference, May 2003.
- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

Expert Testimony/Opinions

On

Rate of Return & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004

Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions
on
Other Issues

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

Current Ratings and New Issue Indicated Spreads
Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities

	Current Ratings November 26, 2007		4-10-06	6-12-06	9-5-06	11-6-06	1-2-07	2006 Average	4-2-07	7-3-07	10-9-07	11-26-07	2007 Average
	DBRS	**S&P**											
A Rated													
CU Inc.	A(high)	A	90	94	97	93	92	**93**	90	95	115	130	**108**
Enbridge Gas	A	A-	100	105	100	96	95	**99**	98	110	115	130	**113**
Enbridge Pipelines	A(high)	A-	100	105	100	96	95	**99**	98	105	115	130	**112**
Gaz Metro	A	A	89	94	99	95	97	**95**	94	92	115	135	**109**
Terasen Gas [1/]	A	A	na	na	na	na	na	**na**	na	122	135	145	**134**
TransCanada PipeLines	A	A-	117	120	120	116	115	**118**	115	130	140	160	**136**
Average	**A**	**A-**	**99**	**104**	**103**	**99**	**99**	**101**	**99**	**109**	**123**	**138**	**117**
Median	**A**	**A-**	**100**	**105**	**100**	**96**	**95**	**99**	**98**	**108**	**115**	**133**	**113**
Split Rated A/BBB													
EPCOR Utilities	A(low)	BBB+	129	132	133	130	135	**132**	130	136	170	185	**155**
Nova Scotia Power	A(low)	BBB	135	140	142	140	138	**139**	132	136	145	170	**146**
Terasen Gas [1/]	A	A	129	145	142	130	130	**135**	119	na	na	na	**119**
Union Gas	A	BBB+	118	123	120	114	107	**116**	109	109	120	150	**122**
Westcoast Energy	A(low)	BBB+	123	128	125	120	118	**123**	119	119	125	155	**130**
Average	**A(low)**	**BBB+**	**127**	**134**	**132**	**127**	**126**	**129**	**122**	**125**	**140**	**165**	**138**
Median	**A(low)**	**BBB+**	**129**	**132**	**133**	**130**	**130**	**131**	**119**	**128**	**135**	**163**	**136**
BBB Rated													
TransAlta	BBB	BBB	162	168	168	162	170	**166**	170	205	300	325	**250**

[1/] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.8	11.4	3.1
CU Inc.	2.7	18.7	3.6
Enersource	2.1	16.7	3.8
ENMAX Corp.	6.4	46.3	8.1
EPCOR Utilities Inc.	3.0	23.4	4.2
FortisAlberta Inc.[2/]	2.3	17.5	3.0
FortisBC Inc.[2/]	2.2	10.9	2.8
Hamilton Utilities	3.4	32.0	4.7
Hydro One Inc.	3.2	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	26.1	5.7
Maritime Electric	2.5	12.9	2.6
Newfoundland Power [2/]	2.4	14.0	2.9
Nova Scotia Power	2.4	14.2	3.3
Toronto Hydro	2.7	17.5	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	12.5	3.0
Gaz Metropolitain	2.5	24.0	4.6
Pacific Northern Gas [4/]	2.4	26.4	3.2
Terasen Gas	2.0	9.7	2.4
Union Gas [3/]	2.1	12.8	2.8
Pipelines			
Enbridge Pipelines [3/]	3.3	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	15.7	2.8
Westcoast Energy Inc.	2.1	16.4	3.1
Medians			
Electric T&D	**2.7**	**17.5**	**3.8**
Electric Integrated	**2.5**	**14.2**	**3.3**
All Electric	**2.6**	**17.5**	**3.5**
Gas Distributors	**2.1**	**12.8**	**3.0**
All Companies	**2.4**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

Name	S&P Debt Rating	S&P Business Profile	Average 2004-2006 Debt Ratio	Average 2004-2006 EBIT Coverage	Average 2004-2006 FFO/Debt	Average 2004-2006 FFO Coverage	Average ROE 2004-2006
Alabama Power Co.	A	4	54.3	4.3	22.8	5.6	13.5
Central Hudson Gas & Electric Corp.	A	3	66.3	4.7	16.7	4.3	12.2
Consolidated Edison Co. of New York Inc.	A	2	54.8	2.8	18.7	3.9	10.0
Consolidated Edison Inc.	A	2	57.2	2.6	16.7	3.7	9.2
Duke Energy Carolinas LLC	A-	4	48.0	4.0	28.8	14.9	NA
Duke Energy Corp.	A-	5	48.7	3.2	19.8	3.9	9.9
Duke Energy Indiana Inc.	A-	4	56.7	3.1	17.6	4.6	8.8
Duke Energy Ohio Inc.	A-	5	38.7	4.5	23.2	5.6	11.0
Florida Power & Light Co.	A	4	41.1	5.9	34.1	7.7	11.7
FPL Group Inc.	A	5	51.8	2.7	22.3	4.5	12.4
Georgia Power Co.	A	4	56.0	4.6	22.0	6.1	14.1
Gulf Power Co.	A	4	54.5	3.7	20.9	4.6	12.2
Integrys Energy Group Inc.	A-	5	58.6	3.4	13.8	4.1	12.5
KeySpan Corp.	A-	3	61.8	3.5	16.2	3.9	10.4
Madison Gas & Electric Co.	AA-	4	52.4	4.5	20.4	5.1	10.6
MidAmerican Energy Co.	A-	5	52.4	4.4	26.0	5.8	14.2
MidAmerican Energy Holdings Co.	A-	4	74.9	1.9	11.1	2.5	13.2
Mississippi Power Co.	A	4	63.0	4.2	22.8	10.8	13.9
NSTAR	A+	1	65.4	3.5	22.6	4.9	13.3
NSTAR Electric Co.	A+	1	49.7	5.7	39.4	8.1	13.8
Orange and Rockland Utilities Inc.	A	2	70.8	3.6	16.9	3.9	NA
PacifiCorp	A-	5	59.0	2.5	15.0	3.7	7.0
PPL Electric Utilities Corp.	A-	3	51.0	3.1	26.2	4.9	NA
San Diego Gas & Electric Co.	A	5	54.8	5.0	25.9	6.7	16.3
SCANA Corp.	A-	4	57.6	2.5	22.5	4.2	11.4
South Carolina Electric & Gas Co.	A-	4	50.1	2.6	25.6	5.1	10.3
Southern Co.	A	4	57.0	3.8	22.3	5.3	14.9
Vectren Corp.	A-	4	60.4	2.7	15.9	3.9	10.5
Wisconsin Electric Power Co.	A-	4	52.5	4.8	25.0	6.8	11.8
Wisconsin Power & Light Co.	A-	4	48.1	3.6	31.1	5.9	9.9
Wisconsin Public Service Corp.	A	4	52.3	4.0	22.3	5.4	10.1
Mean	**A**	**4**	**55.5**	**3.7**	**22.1**	**5.5**	**11.8**
Median	**A**	**4**	**54.8**	**3.6**	**22.3**	**4.9**	**11.8**

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 1, 2007; *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest,* November 9, 2007; and *Credit Stats,* September 2007.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures (DBRS) Issuer (S&P)	A		A-	
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [2/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
TransCanada PipeLines	Senior Secured	A		A	Very conservative
	Senior Unsecured	A	A2	A-	
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Electric T&D		**A**	**Baa1**	**A-**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**BBB+**	**Very conservative**
All Electric		**A**	**Baa1**	**A-**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
All Companies		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd. [4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES (Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity		Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	
Electric Utilities										
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00		8.75	4.55	
ATCO Electric		EUB								
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00		8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00		8.75	4.55	
EPCOR		EUB								
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00		8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00		8.75	4.55	
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00		8.75	4.55	
FortisBC Inc.	3/06; 11/07	BCUC	G-14-06; L-93-07	60.00	0.00	40.00		9.02	4.55	
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00		8.35	4.16	
Maritime Electric	6/06	IRAC	UE20934	57.31	0.00	42.69		10.25	na	
Newfoundland Power	10/07	NLPub	Settlement Agreement	54.01	1.15	44.84		8.95	4.60	1/
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50		9.55	na	2/
Northwest Territories Power Corp.	8/07	PUB of NWT	Decision 13-2007	52.26	0.00	48.59	3/	9.25	4.60	
Ontario Electricity Distributors	12/06	OEB	Report of the Board	60.00	0.00	40.00		8.98	5.00	4/
Yukon Energy	10/05	YUB	OIC 1998/32; Order 2005-12, BCUC G-55-07	60.00	0.00	40.00		9.15	4.55	5/
Gas Distributors										
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00		8.75	4.55	
Enbridge Gas Distribution Inc	1/04; 7/07	OEB	RP-2002-0158; EB-2006-0034	61.33	2.67	36.00		8.39	4.23	
Gaz Metropolitain	10/07	Régie	D-2007-116	54.00	7.50	38.50		9.05	4.78	
Pacific Northern Gas	11/07; 5/07	BCUC	L-93-07; G-55-07	56.20	3.80	40.00		9.27	4.55	
Terasen Gas	3/06; 11/07	BCUC	G-14-06; L-93-07	65.00	0.00	35.00		8.62	4.55	
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00		8.54	4.23	
Gas Pipelines										
Alberta Natural Gas	11/07; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00		8.72	4.55	
Foothills Pipe Lines (Yukon) Ltd.	11/07; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00		8.72	4.55	
TransCanada PipeLines	11/07; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00		8.72	4.55	
Trans Quebec & Maritimes Pipeline	11/07	NEB	RH-2-94	70.00	0.00	30.00		8.72	4.55	
Westcoast Energy	11/07; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00		8.72	4.55	

1/ The settlement agreement specifying ROE and capital structure is subject to PUB approval.

2/ A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35% if approved.

3/ The capital structure of NTPC includes no cost capital (-.85%).

4/ The 8.98% is the return on equity that would apply at a forecast yield of 5.0% as per the Board's December 2006 report.

5/ The YUB sets YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Board Decisions.

Northland Utilities (NWT) Limited

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
January 2008

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of, and a senior consultant with, Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, oil and gas pipelines, and telephone companies in more than 150 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Northland Utilities (NWT) Limited (NUNWT) has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity for the Company's 2008-2010 test years.

In Decision 13-2007 (August 2007) for Northwest Territories Power Corporation (NTPC), the Public Utilities Board of the Northwest Territories ("PUB" or "Board") stated that "the Board would prefer to see all of the business risk adjustment reflected in the capital structure rather than in the capital structure as well as in the return on common equity."[1] In recognition of the PUB's preference, I have estimated capital structures that fully reflect the business risks of NUNWT. Based on my analysis, the common equity ratio that would fully compensate for the business risks of NUNWT lies at the upper end of a range of 50-55%.

At a common equity ratio of 55%, the allowed return on equity for NUNWT should be equal to that applicable to an average risk Canadian utility, that is, a benchmark return on equity. For the express purpose of this proceeding, I recommend adopting the benchmark

[1] Public Utilities Board of the Northwest Territories, *In the Matter of an Application by Northwest Territories Power Corporation*, Decision 13-2007 (August 29, 2007), page 47

return on equity derived from the PUB's Decision 13-2007, adjusted for changes in interest rates. The benchmark return on equity adopted by the PUB was 8.75%, based on a long-term Canada bond yield of approximately 4.6%.

With respect to the return on equity for test years 2008-2010, I recommend that the PUB:

1. Adopt a simple return on equity for all three test years, based on the forecast average long-term Government of Canada bond yield of 5.0%; and,

2. Apply the automatic adjustment formula adopted by various Canadian regulators using the 8.75% benchmark return on equity and 4.6% long-term Canada bond yields adopted in Decision 13-2007 as points of departure.

The application of the automatic adjustment formula at a forecast long-term Canada bond yield of 5.0% results in a benchmark return on equity of 9.1%. The indicated benchmark return on equity of 9.1% is applicable to NUNWT at a common equity ratio of 55%.

However, increasing the actual common equity ratio of NUNWT to 55% could require shareholders to raise additional debt capital to effect the change, thus exposing them to incremental financial risks. Moreover, requiring shareholders to commit additional equity capital to have the opportunity to earn a benchmark equity return regarded as too low is fundamentally incongruous. As a result, I recommend increasing the actual common equity ratio of NUNWT to 50% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 50% equity ratio and the 55% common equity ratio that would fully compensate for the business risks of NUNWT. At a common equity ratio of 50%, the allowed ROE for NUNWT should be set at 9.6%.

II. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN COST OF CAPITAL AND CAPITAL STRUCTURE

The cost of capital is largely a function of business risk, that is, of the risks arising from the operations/assets of a firm. The cost of capital, however, is also a function of financial risk, i.e., additional risk borne by the common equity shareholder because the firm is using fixed obligation securities (e.g., long-term debt) to finance a portion of its assets. Therefore, the capital structure, comprised of fixed obligation securities and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used.

However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will accompany an increase in the cost of equity.

B. APPROACHES TO DETERMINING THE FAIR RETURN ON EQUITY

Recognizing the relationship between the cost of capital and capital structure, there are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks, then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or benchmark. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an

adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines.[2] It is also the approach that was adopted by the Alberta Energy and Utilities Board (EUB) in Decision 2004-052 (July 2, 2004). In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/EUB approach as long as the combination of actual/allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark return on equity. The combination of capital structures and equity risk premiums has also been used in Ontario and Québec.

In recognition of the PUB's preference to reflect differences in business risk through capital structure alone, I have estimated the capital structure that fully reflects the business risks of NUNWT. In other words, I have estimated a capital structure for

[2] In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002, 36% in 2005 and 40% in 2007.

NUNWT, based on the principles set out in Section III, that would be compatible with the application of a benchmark return on equity to NUNWT.

C. BENCHMARK RETURN ON EQUITY

1. Conceptual Considerations

Both approaches to determining a fair return outlined in Section II.A rely on the measurement of the equity return that would be applicable to a benchmark utility or average risk Canadian utility. That return will be referred to as a benchmark return on equity. A capital structure for NUNWT would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return; and (c) would equate the level of total (business and financial) risk faced by NUNWT to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the common equity ratio for NUNWT is established so that no adjustment to the benchmark return on equity is required.[3]

The term benchmark utility is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the benchmark utility reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve a particular debt rating, typically an A rating. The typical, average risk Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's (S&P).

[3] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999.

Designation of a debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would require lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return on equity.

In Decision 13-2007, the PUB established a return on equity for NTPC for 2007/08 of 9.25%. The allowed return on equity of 9.25% expressly included a 50 basis point upward adjustment to compensate for the relatively higher risk of NTPC. As noted at page 43 of the decision, the 50 basis point additional risk premium was adopted for NTPC in relation to the return on equity applicable to a benchmark utility. From these findings, it may be reasonably inferred that the PUB considered a return on equity of 8.75% (at a long-term Canada bond yield of 4.50-4.65%[4]) to be equivalent to a benchmark return on equity.

[4] Although the PUB did not specify the long Canada yield in its decision, the range of 4.50-4.65% represents the range of forecasts for 2007/08 provided by the experts in this proceeding.

2. Benchmark Return on Equity for Test Years 2008-2010

Expert testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Preparation of testimony, responses to information requests and cross-examination of witnesses entail a considerable amount of money, time and effort. As a result, the cost impact on a utility the size of NUNWT can be significant. Since the PUB recently undertook a comprehensive review of the return on equity and detailed its findings in a decision released less than six months ago, NUNWT is prepared to accept the PUB's benchmark return on equity as a point of departure for establishing its allowed return on equity for the 2008-2010 test years, as adjusted for changes in interest rates. By using the benchmark return on equity established in Decision 13-2007 as a point of departure, the costs associated with the determination of the allowed return on equity for NUNWT should be greatly reduced. The cost of capital testimony can then focus on the issue of capital structure that is required to fully compensate for the utility's risks and, if necessary, given the specific financing considerations of the utility, any incremental equity risk premium relative to the benchmark return on equity that is required.

Given these considerations, I accept, for the express purposes of this proceeding, that the benchmark return on equity determined by the PUB in Decision 13-2007, as adjusted for changes in interest rates since the decision was issued, will be used as the basis for establishing the allowed return on equity for NUNWT. [5] That return on equity, however, can only be applied to a common equity ratio that fully compensates for NUNWT's business risks.

To adjust the benchmark return on equity established in Decision 13-2007 for changes in interest rates, an automatic adjustment mechanism can be used. Automatic adjustment mechanisms for determining a utility's allowed return on equity are relied upon in six different regulatory jurisdictions in Canada. The various mechanisms are all quite

[5] In my opinion, the benchmark return on equity established in Decision 13-2007 is below the level commensurate with the comparable returns standard.

similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a base, or initial, return on equity and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base allowed return on equity are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula, or adjustment factor, to be used to adjust the allowed return on equity from one year to the next. The forecast yield on the long-term Government of Canada bond is used as the proxy for the risk-free rate.

Application of an adjustment mechanism like those used in most Canadian jurisdictions requires the following steps:

Step 1: Establish the forecast long-term Canada bond yield for the test year(s),

Step 2: Apply the adjustment factor to the difference between the test year forecast(s) of the long-term Canada bond yield and the bond yield underlying the base allowed return on equity, and

Step 3: Adjust the base allowed return on equity by the amount(s) determined in Step 2.

In five of the six Canadian jurisdictions that currently use an automatic adjustment mechanism,[6] the adjustment factor is set at 0.75, i.e., the change in allowed return on equity equals 75% of the change in the forecast long-term Government of Canada bond yield. In my opinion, a 75 basis point change in allowed return on equity for every one percentage point in the forecast long term Government of Canada bond yield is a reasonable approximation of the relationship between the cost of equity and interest rates.

[6] The five regulatory boards that use automatic adjustment mechanisms with a 0.75 adjustment factor are the Alberta Energy and Utilities Board, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board, and the Régie de l'Energie de Québec. In Newfoundland and Labrador, the adjustment factor is 0.80.

As indicated in Section II.C.1 above, a benchmark return on equity of 8.75% (at a long-term Canada bond yield of 4.50-4.65%) can be inferred from the PUB's 2007/08 allowed return on equity for NTPC. NUNWT is proposing rates for a three-year test period, 2008-2010. I recommend that the PUB adopt a single return on equity for the three test years, based on the average forecast long-term Government of Canada bond yield during the three test years.

Consensus Economics, *Consensus Forecasts* (October 2007) anticipates the following 10-year Government of Canada bond yields:

Table 1

January 2008	October 2008	2008[1/]	2009	2010
4.4%	4.7%	4.55%	5.1%	5.1%

[1/] Average of the January and October 2008 forecasts.

The average forecast 10-year Government of Canada bond yield for 2008-2010 is 4.95%.[7]

The yield curve at the end of October 2007 was relatively flat; the spread between the 10 year and the long-term Canada bond yields was seven basis points. The addition of a spread of seven basis points to the average 2008-2010 10-year Canada bond yield forecast of 4.95% results in a forecast long-term Canada bond yield of just over 5.0%. While the three year average forecast long-term Canada bond yield of 5.0% is somewhat higher than the forecast for 2008 alone, NUNWT is taking the risk that the actual long-term yields in 2009 and 2010 will be higher than currently anticipated.[8]

[7] The five Canadian regulatory boards that use a 0.75 adjustment factor referenced in footnote 6 also all rely on *Consensus Forecasts*' outlook for 10-year Canada bond yields, from which they then derive a forecast of the long-term Government of Canada bond yield. There is no consensus forecast of the long-term Canada bond yield.

[8] On average, historically, the spread between 10-and 30-year Canada bond yields has been 30 basis points. If the yield curve reverts to a more normal upward slope over the test period, even if the 10-year Canada

Based on a 5.0% long-term Canada bond yield forecast, the benchmark return on equity (ROE) for NUNWT's 2008-2010 test years is calculated as follows:

Benchmark $ROE_{5\%}$ = Benchmark $ROE_{Initial}$ + Adjustment Factor x ($Current_{BY}$ – $Initial_{BY}$)
Benchmark $ROE_{5\%}$ = 8.75% + 0.75 * (5.0% – 4.6%)
Benchmark $ROE_{5\%}$ = 9.1%

I recommend, therefore, that a benchmark return on equity of 9.1% be adopted for all three test years; the 9.1% would be applicable to the common equity ratio estimated in Sections III to VIII. If, however, the common equity ratio adopted for ratemaking purposes is lower than that which would fully compensate for NUNWT's business risks, then an upward adjustment will need to be made to the benchmark ROE for NUNWT's higher financial risks.

III. PRINCIPLES FOR CAPITAL STRUCTURE

The following principles should be respected when establishing the appropriate capital structure for NUNWT:

A. The Stand-Alone Principle.
B. Compatibility of Capital Structure with Business Risks.
C. Maintenance of Creditworthiness/Financial Integrity.

Each of these principles is defined below.

bond yield forecasts during 2009-2010 turn out exactly as currently anticipated, long term Canada bond yields will be higher than the forecast.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by NUNWT should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

NUNWT is 76% owned by ATCO Electric with the remaining 24% owned by Denendeh Investments Limited Partnership (14%) and Arctic Energy Investors Group (10%). ATCO Electric, in turn, is a wholly-owned subsidiary of CU Inc. NUNWT operates as a stand-alone entity (separate from the other electric utility operations of ATCO Electric). CU Inc. raises debt on behalf of NUNWT. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities, including NUNWT, at the cost incurred by CU Inc. NUNWT's customers receive the benefits of those ratings. In turn, NUNWT should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the benefits of debt costs that reflect an A(high)/A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

Based on the indicated spreads for new issues as published by RBC Capital Markets, CU Inc. has been able to raise new 30-year debt on average at approximately 110 basis points over a similar term Government of Canada bond during 2007. Spreads for utilities with one debt rating in the BBB category (split-rated utilities) have ranged from 122 basis points (Union Gas rated A by DBRS and BBB+ by S&P) to 155 basis points (EPCOR Utilities, rated A(low) by DBRS and BBB+ by S&P) and have averaged approximately 135-140 basis points (See Schedule 1).

The 2007 average masks the widening spreads during the year. As investors have become more risk-averse during the year, and the outlook for the economy has deteriorated, credit spreads have widened since the end of 2006. At the end of November 2007, the indicated spread for a new 30-year CU Inc. issue was 130 basis points versus 95 basis points a year earlier. Spreads for new split-rated A/BBB issues have increased from approximately 125-130 basis points to 165 basis points over the same period.

Depending on the state of the capital markets, the spread between the cost of a new long-term debt issue for a strong A credit and one for a split A/BBB credit can be much higher than it is currently. Within the past five years, the spread has been as high as 100 basis points.

With respect to electric power corporations that are still investment grade but rated in the BBB category by all the debt rating agencies, there is only one conventional equity corporation (i.e., non-income trust) included in the S&P/TSX Utilities Sector, TransAlta Corporation. The average indicated spread for a new 30-year TransAlta Corporation debt issue during 2007 has been 250 basis points; at the end of November 2007, the spread was 325 basis points. (Schedule 1) The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long term debt of approximately 195 basis points provides a perspective on the potential magnitude of the benefits to ratepayers of NUNWT's affiliation with CU Inc. As a true stand-alone entity, NUNWT would not be able to obtain investment grade debt ratings given its small size. The estimation of an appropriate capital structure for NUNWT should recognize the magnitude of the cost benefits conferred upon ratepayers arising from NUNWT's ability to access debt capital through CU Inc. rather than on its own.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

For larger utilities like CU Inc. which regularly access the public debt markets, a reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult or weak capital market conditions.

As noted above, NUNWT is too small to have its own debt ratings (i.e., it would not be investment grade) or to access the public debt markets on its own. If it were to access third-party debt on its own, its options would be limited to banks or insurance companies at a significantly higher cost than is available to CU Inc., and with more stringent covenants. A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to NUNWT both the actual cost of debt that NUNWT would be able to obtain on its own and the capital structure that would be required by a potential lender to provide debt capital in the absence of its affiliation with CU Inc. (that is, for example, if its sole equity shareholders were the Denendeh Investments Limited Partnership and Arctic Energy Investors Group).

To my knowledge, the only small (total capital less than $100 million) regulated company that has accessed debt on a true stand-alone basis within the past five years is Natural Resource Gas (NRG), a small Ontario natural gas distributor. NRG was able to obtain five-year bank financing during 2005, a period of easy credit, at a spread over five-year Government of Canada bond yields of approximately 280 basis points. At the same time, the larger gas utilities (with debt ratings in the A/BBB rating categories) were able to issue five-year debt at spreads of 40-45 basis points over five-year Government of Canada bond yields. At the time, TransAlta Corporation was able to raise five-year debt at approximately 70 basis points above a similar term Government of Canada bond yield. NRG is of similar size to NUNWT (assets of approximately $9 million), but of somewhat lower business risk. Nevertheless, NRG's stand-alone cost of debt provides a further indicator of the order of magnitude of the benefit that NUNWT's ratepayers receive as a result of NUNWT's affiliation with CU Inc.

My assessment of the appropriate capital structure for NUNWT balances the stand-alone and creditworthiness and financial integrity principles with a recognition that the impact of small size on lenders' willingness to lend funds and on the stand-alone cost of debt would be, in part, related to the lack of liquidity and institutional interest in small debt issues rather than to fundamental business risk factors. Nevertheless, the appropriate capital structure and return on rate base for NUNWT needs to recognize the cost benefits that NUNWT's ratepayers receive.

IV. BUSINESS RISK

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short-term and long-term risks. Long-term risks are important because utility assets are long-lived. Moreover, utility stocks are not typically purchased as short-term investments. Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall higher return rewards when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future.

Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

Market demand risk relates to those factors that can lead to annual volatility in electricity sales or loss of customers. It includes market size, economic diversity and strength of the service area, growth potential, concentration of sales, competition with alternative energy sources and weather.

Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity. The physical risks of the utility are a function of its geography, mix of generation and ability to access alternative sources of supply.

The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

NUNWT is a very small integrated electric utility serving approximately 2,600 customers in eight communities in the south central portion of the Northwest Territories. The largest community served is the Town of Hay River, with a population of 3,650. The populations of the other communities range from approximately 50 to 725. Total sales are approximately 35 GW.h. To put this in perspective, the following table compares customers, sales, and rate base of major Canadian investor-owned and government-owned electric utilities with rated debt, i.e., not guaranteed.

Table 2

Company	Customers	Sales (GW.h.)	Rate Base ($ Millions)
NUNWT	2,600	35	12
Electric Utilities with Rated Debt:			
ATCO Electric	216,000	10,300	1,500
EPCOR Utilities	318,000	7,100	500
FortisAlberta	430,000	14,700	800
FortisBC	152,000[1/]	3,100	680
Hydro One	1,300,000	29,300	8,400
Hydro Ottawa	280,000	7,500	500
Maritime Electric	66,000	1,000	200
Newfoundland Power	229,500	5,000	750
Nova Scotia Power	460,000	11,600	2,900

1/ Includes both direct (approximately 100,000) and indirect customers.

As the table above indicates, NUNWT is approximately one-sixteenth the size of the smallest utility (Maritime Electric) with its own debt ratings. From a business risk fundamentals perspective, small size limits a utility's ability to diversify its risks geographically, operationally and among services provided.

NUNWT has franchise agreements to serve its communities which must be renegotiated periodically. The majority of the existing agreements expire within three years; the franchise to serve the largest community, the Town of Hay River, expires in 2010. The risk of franchise non-renewal is relatively higher for NUNWT than many other electric utilities because of the proximity of Northwest Territories Power Corporation (NTPC).

NUNWT's customer profile, based on 2007 actual data, is as follows:

Table 3

	Residential	General Service	Street & Sentinel Lighting
Sales ($000)	3,716	4,438	264
Customers	1,979	631	na

While NUNWT currently has no industrial customers of its own,[9] the economic base of the Northwest Territories (NWT) will have secondary impacts on the residential and commercial customer load. The NWT's industrial base is dominated by a single volatile industry, diamond mining, accounting for approximately half of GDP in 2006. The risks associated with diamond mining include world-wide supply and demand, the latter being tied to the availability of discretionary income globally, the uncertainty associated with the forecast versus actual reserves, including the quality of those reserves, the impact of currency fluctuations on both costs and revenues, the impact of higher than expected costs of exploration, development and production, and the potential impact of changes in environmental standards and social policies. Diamond mining in the NWT comprises the additional risk associated with the impacts of climate on the ability to operate and the costs of operation.[10] The fortunes of the diamond mining industry will impact in-migration and out-migration as well as the fortunes of commercial enterprises that have developed either in direct support of the industry (e.g., diamond cutting and polishing) or indirect support of the recent growth in population.

Partly offsetting the potential volatility of the diamond mining industry is the stabilizing impact of government-related load (e.g., schools, municipal government offices). Government-related load contributes a degree of stability to NUNWT's overall revenues, as government-related load is less likely to be impacted by economic swings than other customer groups.

The NWT has experienced large variations in GDP growth over the past few years, largely due to the diamond mining sector. In 2003, the NWT experienced the highest level of economic growth in the country (13.4% versus 1.9% for Canada), with the

[9] NUNWT has been approached by Tamerlane Ventures, a zinc-lead mining company, to provide service to the Pine Point mine site commencing in 2008. Tamerlane's power requirements would increase NUNWT's sales (in GWhrs) by 50%. My assessment of the business risks of NUNWT is premised on the assumption that any arrangement between Tamerlane and NUNWT would not impose any additional business risks on NUNWT.

[10] Jericho Diamond Mine located in Nunavut, the most recently opened (March 2007) mine, reported a 3rd Quarter 2007 asset impairment charge, arising from ongoing operational and production issues, the appreciation of the Canadian dollar and rising input costs. The company (Tahera Diamond Corporation) reported that a shortage of funds it was forced to defer its scheduled debt repayments.

opening of a second diamond mine. Economic growth remained relatively strong in 2004, increasing 3.6% (versus Canada's 3.1%). However, in 2005, the NWT's economic growth turned negative as both the value and production of the diamond industry declined, largely due to the appreciation of the Canadian dollar and the processing of lower grade ore. The reduction in mining value and output resulted in territorial growth contracting 2.5%, the lowest rate of growth in the nation. In 2006, economic growth rebounded to 2.9%, approximately the same rate of growth as for all of Canada (2.8%).[11] The widely divergent rates of annual growth demonstrate the potential volatility in the economy.

Not only do the actual rates of growth exhibit considerable volatility, there can be significant differences between the forecast and the actual rates of growth. For example, in February 2007, the Government of the Northwest Territories, in its *2007-2010 Business Plans* forecast a 2006 rate of real GDP growth of approximately 8%. The actual rate, as indicated above, was only 2.8%. The potential variance between forecast and actual rates of growth enhances NUNWT's forecasting risk. On the cost side, forecasting risks are further increased by the tight labour market, particularly for skilled workers, rising wages and rising costs of basic materials.

Electric utilities, including NUNWT, are subject to the risk of lost sales arising from the increasing emphasis on energy efficiency, conservation and reducing peak load. Lost load due to energy efficiency and conservation efforts reduces the utility's earnings. The GNWT's *Energy for the Future: An Energy Plan for the Northwest Territories*, released in March 2007, emphasizes the implementation of energy conservation and efficiency initiatives, with the objective of reducing energy costs and environmental impacts.[12]

With respect to supply and physical risks, NUNWT faces a significantly higher level of risk relative to other Canadian electrical utilities. NUNWT's service area is comprised of

[11] Statistics Canada, *The Daily, Provincial and Territorial Economic Accounts*, November 8, 2007.
[12] A number of regulatory jurisdictions in North America have implemented or are investigating revenue decoupling (decoupling revenues from consumption) to address this issue.

multiple communities which are unconnected by a single system grid, which prevents them from accessing alternative sources of power. In Hay River, the company purchases power from NTPC's Talston hydroelectric system and maintains a back-up diesel generation plant. In the smaller, more remote communities, NUNWT both generates and distributes power.

Approximately 28% of NUNWT's rate base is comprised of diesel generation assets. The presence of generation assets in rate base increases the business risk of NUNWT relative to a pure distribution utility, as the operational risks associated with generation exceed those of "wires" operations. In the case of NUNWT, the operating risks are exacerbated by the severe climate in which the utility operates, both in terms of the risk of outages and the potential unanticipated impacts of repair, both in terms of time and expenditures. While NUNWT has deferral accounts for diesel fuel costs, the high cost of diesel fuel creates an additional incentive to conserve energy (thus leading to lower than expected sales). Further, in contrast to hydroelectric generation, diesel generation is exposed to greater risks of complying with increasingly stringent environmental standards.

With respect to regulatory risk, as independent tribunals, regulators have the power to expose utilities to relatively high risks, by, for example, disallowing costs, approving rate designs that are tilted against recovery of fixed costs, or returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility an opportunity to achieve a fair return with a reasonably high probability. This explains why regulation is considered to be a key element of a utility's business risk profile. On balance, the regulatory environment in the NWT has been even-handed and reasonable in its approach. The Board has granted deferral accounts for costs that are beyond the control of management, including power costs, diesel fuel and generation costs, plant maintenance expense and rate case expense.[13] Nevertheless regulatory decisions can also have a negative impact on utilities.

In the recent NTPC decision, the Board required NTPC to refund to customers amounts related to brushing costs that had been forecast by NTPC for earlier test years but not spent. While this action arguably constituted retroactive ratemaking, the Board recently vacated that direction, following a review of the decision.

On balance, as a very small utility operating in a service territory with an undiversified economic base tied to a single industry and facing significant geographic physical/operating challenges, NUNWT:

- is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada,
- is of higher than average business risk within the spectrum of Canadian utilities and,
- is of higher business risk than its sister utility in the NWT, Northland Utilities (Yellowknife) Inc.[14]

In light of the PUB's stated preference in Decision 13-2007, I have estimated the capital structure for NUNWT that would compensate for NUNWT's higher business risk in Sections V to VIII below.

[13] The existence of these deferral accounts does not constitute a guarantee that the costs accrued in the account will be recoverable from customers.
[14] An analysis of the business risks of Northland Utilities (Yellowknife) Inc. is found in the Return on Rate Base Section of the NUY GRA filing.

V. CAPITAL STRUCTURES OF PEERS

The determination of the capital structure that reflects NUNWT's business risks and would be compatible with the application of the benchmark return on equity requires comparisons with the capital structures of other electric utilities for two reasons. First, electric utilities which raise debt in the public markets (and, therefore, have debt ratings) have capital structures that have been "tested" by the capital markets. Thus, their capital structures, in conjunction with other key financial metrics (e.g., coverage ratios), provide an indication of the capital structure required to maintain investment grade debt ratings. Second, the common equity ratios allowed for other electric utilities (whether or not their debt is rated), either through regulatory decisions or settlements, provide a measure of the level that is warranted for an electric utility to compete for capital with its peers, with due regard to differences in business risk.

Table 4 below sets out the average actual common equity ratios of Canadian electric utilities with rated debt, as well as those of low risk U.S. electric utilities with debt rated in the A category.

Table 4

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	43.4%
Transmission & Distribution	A/Baa1/A-	44.5%
Integrated	A(low)/Baa2/BBB+	40.5%
U.S. A-rated Electric Utilities	na/A2/A	49.0%

Source: Schedules 2, 3 and 4.

Table 4 indicates that the average actual common equity ratios for all Canadian electric utilities with rated debt and for Canadian transmission and distribution utilities have averaged close to 43.5% and just below 45% respectively. The corresponding debt ratings by all three debt rating agencies have been, on average, approximately A-/A(low). Given NUNWT's higher than average business risks, the equity ratios maintained by other Canadian electric utilities indicate that a 45% common equity ratio would be too low to fully compensate for its business risks. Maritime Electric, the smallest of the rated investor-owned utilities, and the one that would be considered the closest comparator of NUNWT, has a target actual common equity ratio of 45%. While it is the closest comparator, it is significantly larger and faces lower business risk than NUNWT. Moreover, its allowed return on common equity has been materially higher than the PUB's benchmark return on equity.[15] The comparison with Maritime Electric strengthens the conclusion that a 45% common equity ratio (at the benchmark return on equity) is well below the level required to fully compensate for NUNWT's business risks. With respect to other utilities regulated by this Board, for the 2007/08 test year, the PUB adopted a common equity ratio of 48.86% and an incremental equity risk premium of 0.50% for NTPC, which faces somewhat higher business risk than NUNWT. The corresponding equity ratio for NTPC that would fully compensate for its higher business risks would be approximately 56-57%. Since NTPC faces somewhat higher business risk than NUNWT, the fully compensatory equity ratio for NUNWT indicated by the Board's decision would be slightly lower than 56-57%.

As the capital market has become increasingly global, Canadian utilities increasingly find themselves competing with foreign utilities for financing. The similarities and proximity of the U.S. and Canadian capital markets make comparisons with U.S. electric utilities especially relevant. The major bond rating agencies increasingly draw comparisons between Canadian utilities and their U.S. peers. Thus, the capital structures of U.S. electric utilities of reasonably similar business risk to NUNWT and with debt rated in the A category may provide some guidance.

[15] Maritime Electric serves the relatively sparsely populated Prince Edward Island, is dependent upon New Brunswick Power for the majority of its power supply, but also has approximately 27.5% of its net property, plant and equipment assets invested in generation. Maritime Electric, which is not subject to an automatic adjustment formula, was allowed a common equity return of 10.25% for the 2006 test year. By comparison, the EUB generic return on equity for 2006 was 8.93%. The difference of approximately 1.25% in ROE is equivalent to approximately 15-20 percentage points in equity ratio.

Since 1999, S&P has assigned to utilities a business risk score in a range of “1” to “10”, where “1” indicates the lowest level of business risk, and “10” the highest.[16] As of November 2007, the median business profile score of the U.S. electric utilities with debt rated in the A category was “4”. By comparison, the average S&P business profile score assigned to Canadian utilities has been “3”. The majority of these companies are largely “wires” or “pipes” companies. While NUNWT is primarily a “wires” utility, as previously discussed, it also has a significant generation component of rate base.[17] As discussed in Section IV, NUNWT would be viewed as facing higher business risks than the typical Canadian utility. On balance, based on its business risk fundamentals, NUNWT would, on a stand-alone basis, be assigned a business profile score of no less than “4”, which is higher than the score assigned to the typical Canadian utility, but the same category as the A rated U.S. utilities. Given it extremely small size, the stand-alone business profile score could be as high as “5”, that is, equivalent to an average risk utility.

The higher business risk of the A-rated U.S. electric utilities relative to the typical Canadian electric utility is partly reflected in higher common equity ratios. As indicated in Table 4 above, the median 2006 actual common equity ratio of U.S. electric utilities with debt rated in the A category was 49.0%. Given the considerably smaller size of NUNWT relative to the A rated U.S. electric utilities, the U.S. electric utilities’ 49% median equity ratio, in isolation, would be a conservative benchmark for NUNWT. Moreover, as discussed in more detail in Section VII, the debt ratings of utilities in a particular business risk category are not solely driven by capital structures. They are also driven by other financial parameters, including coverage ratios. Coverage ratios are a function of cash flows, which, in turn, are dependent upon equity returns. The common equity return for the A rated U.S. electric utilities over the past three years (2004-2006) has averaged 11.8% (see Schedule 2), compared to the 9.1% benchmark return on equity

[16] The key qualitative factors that S&P evaluates in assessing the business risk of regulated electric utilities include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities’ creditworthiness.

[17] Newfoundland Power, for example, was assigned a business risk profile score of “3”. Newfoundland Power would be considered to face lower business risks than NUNWT, given its size, service area, more comprehensive slate of deferral accounts, including revenue protection against weather variations, and smaller generation component of rate base.

relied upon in this analysis, a difference of close to 1.75 percentage points. Given the similarity in the level of business risk between NUNWT and the A rated U.S. electric utilities, the considerable higher ROE of the A rated U.S. electric utilities relative to the benchmark ROE supports the conclusion that a 50% common equity ratio would be too low to equate NUNWT to a benchmark utility.

With respect to allowed common equity ratios, Table 5 below summarizes the most recently adopted capital structures for major Canadian electric utilities, along with any applicable incremental equity risk premiums. Unlike NUNWT, both NTPC and Yukon Energy are government-owned utilities whose debt is guaranteed by their respective Territorial governments. However, like NUNWT, they are both northern utilities, and they are both largely treated like investor-owned utilities for purposes of establishing capital structure and return on equity.[18]

Table 5

Alberta Taxable Distributors	37.0%
FortisBC	40.0% (plus 0.40% risk premium above BCUC's low risk utility benchmark)
Maritime Electric	42.7% (ROE has been approximately 1.25% higher than Canadian average)
Newfoundland Power	44.5% (risk premium 0.15% higher than benchmark)
Northwest Territories Power	48.6% (plus 0.50% risk premium)
Nova Scotia Power	37.5% (ROE approximately 0.75% higher than Canadian average)
Ontario Electric Distributors	40.0%
Yukon Energy	40.0% (plus 0.52% risk premium above BCUC's low risk utility benchmark) [1/]

[1/] Equal to average of the incremental equity risk premiums of Pacific Northern Gas (65 basis points) and FortisBC (40 basis points); by Order in Council, Yukon Energy's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Schedule 5.

[18] Yukon Electrical Company Limited, an investor-owned northern electric utility and affiliate of NUNWT, has not had its capital structure reviewed by the Yukon Utilities Board since the 1993/1994 test years.

If the capital structure for each of the utilities in Table 5 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47%. Since NUNWT would be of higher business risk than the average of the utilities in Table 5, the 46-47% indicated common equity ratio is lower than the level required to fully compensate NUNWT for its higher business risks.

With respect to U.S. electric utilities, since the beginning of 2005, the average common equity ratio adopted for ratemaking purposes has been 47.4%.[19] The average business profile score of all U.S. electric utilities rated by S&P is "5". Thus, the U.S. electric utility industry as a whole is of similar to or slightly higher business risk than NUNWT. However, the average debt rating of all U.S. electric utilities is only BBB. Consequently, it may be inferred that a common equity ratio of 47.5% is not adequate for a "5" business profile score and an A credit rating. Given NUNWT's similar to somewhat lower business risks than the U.S. electric utility industry in the aggregate, but higher target debt rating (in the A category), the U.S. electric industry average allowed common equity ratio of 47.5% would be below the bottom end of equity ratios required to equate NUNWT to the benchmark utility.

On balance, the actual and allowed equity ratios of other Canadian utilities, and those of U.S. electric utilities (in conjunction with their actual and allowed ROEs), indicate that the required common equity ratio for NUNWT is no less than 50%.

[19] Regulatory Research Associates, *Major Rate Case Decisions, January – September 2007*, October 3, 2007. Allowed returns on equity have averaged 10.4% over the same period.

VI. RATING AGENCY DEBT RATIO GUIDELINES

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), S&P has published the most detailed matrix of quantitative guidelines for different debt ratings.[20] For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds From Operations (FFO[21]) Interest Coverage, and FFO To Total Debt (discussed in Section VII). S&P does not apply their guidelines mechanistically; however, the guidelines do represent one objective basis for evaluating an appropriate stand-alone capital structure for NUNWT.

S&P's debt ratio guidelines for an A debt rating and a business risk scores of "4" and "5", the range of notional business risk scores attributed to NUNWT, are as follows:

Table 6

	"4"	"5"
Total Debt/Total Capital	45.0-52.0%	42.0-50.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

The guidelines for business risk profile scores of "4" and "5" indicate that a common equity ratio in the range of 48% to 58% (mid-range of 50-55%) is warranted for an A rating.

Moody's also has published quantitative guidelines. As with S&P, other factors may outweigh the mechanistic application of the guidelines in determining a rating. However, the guidelines provide "broad guidance on the ratio ranges that may generally be seen at different rating levels".[22] While neither NUNWT nor CU Inc. has a Moody's rating,

[20] DBRS has published guidelines, but the guidelines do not distinguish by either business risk or investment grade rating category.
[21] FFO means Funds from Operations, which equal net income plus non-cash items, including depreciation, deferred taxes and other non-cash expenses, e.g., amortization of regulatory assets.
[22] Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005, page 8.

there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's. Thus Moody's guidelines are applicable to those companies and, in turn, will play a role in the formation of target capital structures among Canadian utilities, with the objective of maintaining investment grade debt ratios.

Canadian distribution utilities are typically considered to be operating in a "low business risk" environment by Moody's due to the high degree of regulation and a supportive regulatory system. However, due to its specific business risk fundamentals and small size, NUNWT would likely be classified as a "medium business risk" utility. Moody's debt ratio guidelines for an A rating for a regulated company of "medium risk" are:

Table 7

Debt/Capital	40.0-60.0%

Source: Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

Based on Moody's guidelines, which indicate an equity ratio of 40-60% for a medium risk company and an A rating, a reasonable common equity ratio for NUNWT compatible with a stand-alone A rating would be in the upper half the range, i.e., approximately 50-60%.

The S&P and Moody's debt ratio guidelines, taken together, support a common equity ratio of approximately 50-60% (mid-point of 55%).

VII. RATING AGENCY GUIDELINES OTHER THAN DEBT RATIO

Based on the actual and allowed equity ratios for other Canadian and low risk U.S. electric utilities (Section V), the rating agency debt ratio guidelines (Section VI) and in consideration of NUNWT's relative business risk (Section IV), a common equity ratio range of 50-55% (mid-point of 52.5%) would be required to equate NUNWT to the benchmark utilities (i.e., one with a credit rating of A).

However, the common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Both S&P and Moody's consider cash flow coverage ratios to be key quantitative financial metrics, specifically FFO Interest Coverage and FFO/Total Debt. If a utility is able to achieve adequate cash flow coverage ratios, despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of return on equity, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's and Moody's guideline ranges for the debt ratio, while an important indicator of an appropriate capital structure, should be referenced with regard to other financial metrics.

Table 8

	S&P		Moody's
	"4"	"5"	"Medium Risk"
FFO Interest Coverage	3.5-4.2X	3.8-4.5X	3.5-6.0X
FFO/Average Total Debt	20.0-28.0%	22.0-30.0%	22.0-30.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006 and Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

I have estimated the FFO Interest Coverage and FFO/Total Debt ratios for NUNWT based on common equity ratios of 50.0% and 55.0%. Specifically, I estimated the ratios using capital structures containing 50.0% and 55.0% equity, each in conjunction with a benchmark return on equity of 9.1%, NUNWT's forecast embedded cost of debt of 6.5% and forecast depreciation expense for 2009. In interpreting the results, it is important to recognize, as noted earlier, that the guidelines are not applied mechanistically.

NUNWT's indicated FFO Interest Coverage ratios are 4.6X and 5.2X at 50.0% and 55.0% equity respectively. The indicated ratios are above the upper end of S&P's guideline ranges of 3.5X to 4.5X for business risk profile scores of "4" and "5" and an A rating. At a 50% equity ratio, the indicated FFO interest coverage is lower than the mid-point of the Moody's guideline range (4.75%), but approximately at the mid-point of the upper half of the range at a 55% equity ratio. The estimated FFO/Total Debt ratios (23.0% and 27.0% at common equity ratios of 50.0% and 55.0% respectively) are within S&P's 20-30% range, as well as within Moody's range. Table 9 (below) indicates that FFO Interest Coverage ratios for NUNWT of 4.6X and 5.2X would be higher than the achieved ratios of other Canadian electric utilities (3.5X). However, the average FFO coverage ratio achieved by the low risk (A rated) U.S. electric utilities (4.9X) is in the middle of the range of FFO coverage ratios estimated for NUNWT at 50.0% and 55.0% equity ratios. Given NUNWT's higher business risks relative to an average risk Canadian utility, it should be expected that the FFO interest coverage ratio would be higher.

As shown in Table 9, the FFO/Total Debt ratios for NUNWT of 23% to 27% would be higher than the achieved FFO/Total Debt ratios of other Canadian and low risk U.S. electric utilities.

Table 9

Electric Utilities With Rated Debt	Ratings DBRS/Moody's/S&P	FFO Interest Coverage (2004-2006)	FFO to Total Debt (2004-2006)
Canadian Electric Utilities:			
All	A/Baa1/A-	3.5X	17.5%
Transmission & Distribution	A/Baa1/A-	3.8X	17.5%
Integrated	A(low)/Baa2/BBB+	3.3X	14.2%
U.S. A-rated Electric	na/A2/A	4.9X	22.3%

Source: Schedules 2 and 3.

Although S&P no longer publishes a guideline range for pre-tax (or EBIT)[23] interest coverage ratios, it is still considered an important quantitative financial ratio by all three debt rating agencies (S&P, DBRS and Moody's). It has also been a key ratio considered by regulators (e.g., EUB and BCUC) in assessing capital structures. Moreover, in contrast to the FFO coverages, which are driven in part by depreciation expense, EBIT coverage is more a function of capital structure and return on equity.

S&P's most recent EBIT interest coverage guideline range for an A rating at "4" and "5" business profile scores was 3.3X to 4.3X (mid-point of 3.8X). [24] At common equity ratios of 50% and 55%, the benchmark return on equity of 9.1%, NUNWT's embedded debt cost of 6.5%, and an income tax rate of 29.5%,[25] NUNWT's EBIT interest coverage would be in the range of approximately 3.0X to 3.4X. Table 10 below demonstrates the calculation of the EBIT interest coverage at a 52.5% common equity ratio.

[23] Earnings before Interest and Taxes.
[24] S&P, *Utilities and Perspectives*, June 1999. The EBIT interest coverage guideline ranges were excluded from the quantitative guidelines after June 2004, but the actual EBIT interest coverage ratios continue to be provided in the annual utilities' *CreditStats* published by S&P.
[25] Statutory combined Federal (18%) and Northwest Territories (11.5%) rate as of 2010.

Table 10

	Cost Rate	Percentage	Weighted Component
	(1)	(2)	(3)=(1)*(2)
Debt	6.51	47.5%	3.09
Common Equity	9.10	52.5%	4.78
Tax Rate (t)	29.5%		
Income Tax = 4.78*(t/(1-t)			2.00
Pre-Tax Return			9.87
EBIT Interest Coverage[1/]			3.2X

[1/] EBIT Interest Coverage = Pre-Tax Return ÷ Weighted Debt Component.

The indicated EBIT interest coverage ratio of 3.0X at a common equity of 50% is below the bottom end of S&P's guideline range; an EBIT coverage ratio of 3.4 times at a 55% ratio is marginally above the lower end of the range.

Table 11 below indicates that an EBIT interest coverage ratio in the range of 3.0 to 3.4 times would be higher than the average for the other Canadian electric utilities. Over the period 2004-2006, the average EBIT coverage ratios for all major Canadian electric utilities were 2.7X. In light of its higher than average business risk, an EBIT interest coverage ratio for NUNWT of 3.0-3.4X would be reasonable relative to the achieved ratios of other Canadian electric utilities. An EBIT coverage ratio of 3.4 times, however, would still be lower than the 3.6X EBIT interest coverage ratio achieved by low risk (A rated) U.S. electric utilities, which is partly attributable to the U.S. utilities' higher achieved returns on equity (11.8%), relative to the 9.1% benchmark return on equity.

Table 11

Electric Utilities With Rated Debt	**Ratings DBRS/Moody's/S&P**	**EBIT Interest Coverage (2004-2006)**
Canadian Electric Utilities:		
All	A/Baa1/A-	2.7X
Transmission & Distribution	A/Baa1/A-	2.5X
Integrated	A(low)/Baa2/BBB+	2.6X
U.S. A-rated Electric	na/A2/A	3.6X

Source: Schedules 2 and 3.

In summary, my estimates of the various financial metrics for NUNWT, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, provide support for a common equity ratio at the upper end of a range of 50-55%, consistent with the mid-point of the S&P/Moody's guideline ranges for capital structure.

VIII. DEBT RATING AGENCY COMMENTARY

As indicated in Sections VI and VII above, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a utility. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity base on which it is allowed to earn, but also the allowed return on equity and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S. The investment community has also indicated to the National Energy Board that it believes the financial parameters adopted for regulated companies are too low.[26]

[26] National Energy Board, *Canadian Hydrocarbon Transportation System*, August 2005, June 2006 and July 2007.

DBRS

DBRS has commented generally on the relatively low common equity ratios and returns that are being allowed in Canada. In a May 2003 commentary, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, DBRS noted that it would like to see both the deemed common equity ratios increased as well as increases in allowed returns to levels more consistent with U.S. returns.

In December 2004, subsequent to the EUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity ratios and equity returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[27] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.[28]

[27] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The ROE of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower ROE is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

[28] Other DBRS reports have referenced the low approved returns on equity as a "challenge" for Canadian utilities, i.e., ATCO Ltd. (January 2007), CU Inc. (January 2007), Union Gas (March 2007) and FortisAlberta (May 2007).

Standard and Poor's

With respect to S&P, in early March 2003, the debt rating agency announced that it was reevaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation). S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

Like DBRS, S&P has made references to the low deemed equity ratios and equity returns allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. For example, S&P commented on the thin equity layers (and the low equity returns) allowed the ATCO group of utilities after the EUB decision, stating,

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004)

In a more recent report for NUNWT's parent, CU Inc. (rated A), S&P stated in reference to the company's businesses in Alberta,

> Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities (S&P, *CU Inc.*, October 26, 2007)

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[29] As indicated above, the "aggressive leverage" is largely a result of regulatory directives.

[29] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

In sum, the debt rating agencies consider the allowed common equity ratios for Canadian utilities to be relatively thin and the allowed ROEs to be relatively low. (Actual equity ratios will generally track allowed equity ratios, as utilities have no incentive to maintain higher equity ratios than allowed by the regulator for ratemaking purposes.)

Based on the views of the debt rating agencies, in the aggregate, the allowed and actual common equity ratios of other Canadian electric utilities would be on the low side as a point of departure for estimating a reasonable capital structure for NUNWT. In that context, the upper end of a 50-55% common equity range would be reasonable for NUNWT and allow the benchmark return on equity to be applied without an incremental equity risk premium.

IX. CHOICE OF CAPITAL STRUCTURE AND RISK PREMIUM

As previously discussed, the Board indicated in Decision 2007-13 that it would prefer to see all of the business risk reflected in the capital structure. In respect of the Board's preference, I have estimated the common equity ratio that would fully compensate for NUNWT's business risk, i.e., the upper end of a range of 50.0% to 55.0%. A common equity ratio of 55.0% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained by NUNWT. To reach an actual common equity ratio of 55.0%, the three shareholders of NUNWT would be required to access additional capital to bring the actual equity ratio up to 55.0% and maintain their proportionate interest.[30]

There are two concerns with this approach. First, while the shareholders are willing to accept the benchmark return on equity as a point of departure for setting the allowed

[30] In principle, the common equity ratio could be simply deemed to be 55% irrespective of NUNWT's actual common equity ratio. This is not without precedent. For example, the Ontario Energy Board has deemed common equity ratios of 40% for all of the electricity distributors under its jurisdiction. The actual equity ratios of the distributors at the end of the 2006 ranged from negative to 100%. However, Canadian regulators generally have been reluctant to adopt deemed common equity ratios that are materially higher than the actual equity ratios that are maintained by the utilities.

return on equity for NUNWT, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in NUNWT (as well as other shareholders) consider the returns that Canadian utilities are allowed to be low begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return. In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities during 2006 and 2007 (through 3rd quarter) has been approximately 10.3%, approximately 1.4 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-12.4%.[31]

Second, in contrast to NUNWT's majority shareholder, the minority shareholders do not have ready access to the equity markets. To raise the additional capital necessary to make the required equity infusion, the principal source of external funds would likely be bank loans. Requiring the minority shareholders to raise debt to make an equity infusion would create an additional level of risk for those shareholders, analogous to purchasing common equity shares on margin. At a benchmark return on equity of 9.1%, the differential between the return on equity that the shareholder has an opportunity (not a guarantee) to earn on his utility investment and the cost of a bank loan is not sufficiently wide to induce the shareholders to accept the additional financial risk that moving the actual equity ratio to 55% would entail.

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[31] The Conference Board of Canada, in reference to allowed returns for U.S. electricity transmission, underscored the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled *Electricity Restructuring: Opening Power Markets*, the Conference Board stated,

> 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. 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.

The same conclusions are relevant to distribution and generation.

These considerations lead me to recommend that NUNWT move to an equity ratio of 50.0%, with the difference between a 50% equity ratio and the 55% ratio that would fully compensate for NUNWT's business risks reflected in an incremental equity risk premium. The estimate of the risk premium recognizes that within the five percentage point range of equity ratios (from 50% to 55%), the overall cost of capital would be relatively constant. In other words, as the equity ratio moves from 55% to 50%, the overall cost of capital would not change; the decrease in the equity ratio would be offset by an increase in the common equity return. As demonstrated in Table 12 below, a decrease in the common equity ratio from 55% to 50% increases the equity return from the 9.1% benchmark return on equity to approximately 9.6%.[32]

Table 12

	Proportion	**Cost**	**Weighted Component**
Debt	45.0%	6.30%	2.84%
Equity	55.0%	9.10%	5.01%
			7.84%
		Tax Allowance at 29.5%	2.09%
		Pre-Tax Cost of Capital	9.93%
Move Equity Proportion to 50.0%			
Pre-Tax Cost of Capital Remains Unchanged at:			9.93%
Less: Weighted Interest Component (6.3% x 50.0%)			3.15%
Pre-Tax Weighted Equity Component			6.78%
Less: Tax at 29.5%			2.00%
After-Tax Weighted Equity Component			4.78%
ROE at 50.0% Equity			
(After-Tax Weighted Equity Component / 50.0%)			**9.57%**

[32] Based on a cost of debt equal to the 5.0% forecast 30-year Long Canada yield plus the November 30, 2007 indicated spread for a new 30-year CU Inc. debt issue of 130 basis points, and the 2010 statutory corporate income tax rate of 29.5%.

The indicated required increase in the common equity return due to the lower equity ratio, and thus the required incremental equity risk premium for NUNWT at a 50% ratio, is approximately 0.50%. A 0.50% incremental equity risk premium results in a recommended ROE for NUNWT of 9.6%.

X. CONCLUSIONS

- In recognition of the PUB's preference to reflect differences in business risk through capital structure alone, I have estimated the capital structure that fully reflects the business risk of NUNWT.

- The return on equity that would be applied to the capital structure that fully compensates for NUNWT's business risk is the Board's benchmark return on equity established in Decision 13-2007, as adjusted for changes in the forecast long-term Canada bond yield.

- I recommend that the Board adopt a single benchmark return on equity for all three test years, 2008-2010, of 9.1%, based on the average forecast of long-term Canada bond yields over the three-year period of 5.0%.

- The capital structure for NUNWT should
    - Respect the stand-alone principle;
    - Be compatible with NUNWT's business risks,
    - Maintain NUNWT's creditworthiness and financial integrity

- NUNWT's business risks are significantly higher than those of the typical Canadian electricity distribution utility, higher than average within the spectrum of Canadian utilities and are higher than its sister utility in the NWT, Northland Utilities (Yellowknife).

- The actual and allowed capital structures of NUNWT's peers, both Canadian and U.S., indicate that, in isolation, the common equity ratio that would equate NUNWT to a benchmark utility would be no less than 50%; taking explicit account of U.S. utilities' considerably higher ROEs relative to the benchmark ROE of 9.1% supports an equity ratio in excess of 50%.

- Debt rating agency guidelines for the debt ratio support a common equity ratio in the range of 50-60%.

- Estimates of the various financial metrics for NUNWT, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for NUNWT should be focused on the upper end of a 50% to 55% range (i.e. at 55%).

- The concerns expressed by the debt rating agencies, as well as other capital market participants, that the common equity ratios of Canadian utilities are too thin (and the ROEs are too low) further support the focus on the upper end of the common equity ratio range for NUNWT of 50% to 55%.

- In sum, the upper end of a 50-55% common equity range would be reasonable for NUNWT and would allow a benchmark return on equity to be applied without an incremental equity risk premium.

- Two factors militate against increasing the actual common equity ratio of NUNWT to 55%:

  (1) The shareholders who would have to raise additional debt capital to effect the change would be exposed to incremental financial risks; and

(2) To require shareholders to commit additional equity capital to have the opportunity to earn an equity return perceived as too low is fundamentally incongruous.

- To address these two factors, I recommend increasing the actual common equity ratio of NUNWT to 50% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 50% equity ratio and the 55% common equity ratio that would fully compensate for the business risks of NUNWT. At a 50% common equity ratio, the allowed ROE for NUNWT should be set at 9.6%.

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 150 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- "Utility Cost of Capital Canada vs. U.S.", presented at the CAMPUT Conference, May 2003.

- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

Expert Testimony/Opinions

On

Rate of Return & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004

Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions
on
Other Issues

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

Current Ratings and New Issue Indicated Spreads
Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities

	Current Ratings November 26, 2007 DBRS	S&P	4-10-06	6-12-06	9-5-06	11-6-06	1-2-07	2006 Average	4-2-07	7-3-07	10-9-07	11-26-07	2007 Average
A Rated													
CU Inc.	A(high)	A	90	94	97	93	92	**93**	90	95	115	130	**108**
Enbridge Gas	A	A-	100	105	100	96	95	**99**	98	110	115	130	**113**
Enbridge Pipelines	A(high)	A-	100	105	100	96	95	**99**	98	105	115	130	**112**
Gaz Metro	A	A	89	94	99	95	97	**95**	94	92	115	135	**109**
Terasen Gas [1/]	A	A	na	na	na	na	na	**na**	na	122	135	145	**134**
TransCanada PipeLines	A	A-	117	120	120	116	115	**118**	115	130	140	160	**136**
Average	**A**	**A-**	**99**	**104**	**103**	**99**	**99**	**101**	**99**	**109**	**123**	**138**	**117**
Median	**A**	**A-**	**100**	**105**	**100**	**96**	**95**	**99**	**98**	**108**	**115**	**133**	**113**
Split Rated A/BBB													
EPCOR Utilities	A(low)	BBB+	129	132	133	130	135	**132**	130	136	170	185	**155**
Nova Scotia Power	A(low)	BBB	135	140	142	140	138	**139**	132	136	145	170	**146**
Terasen Gas [1/]	A	A	129	145	142	130	130	**135**	119	na	na	na	**119**
Union Gas	A	BBB+	118	123	120	114	107	**116**	109	109	120	150	**122**
Westcoast Energy	A(low)	BBB+	123	128	125	120	118	**123**	119	119	125	155	**130**
Average	**A(low)**	**BBB+**	**127**	**134**	**132**	**127**	**126**	**129**	**122**	**125**	**140**	**165**	**138**
Median	**A(low)**	**BBB+**	**129**	**132**	**133**	**130**	**130**	**131**	**119**	**128**	**135**	**163**	**136**
BBB Rated													
TransAlta	BBB	BBB	162	168	168	162	170	**166**	170	205	300	325	**250**

[1/] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.8	11.4	3.1
CU Inc.	2.7	18.7	3.6
Enersource	2.1	16.7	3.8
ENMAX Corp.	6.4	46.3	8.1
EPCOR Utilities Inc.	3.0	23.4	4.2
FortisAlberta Inc.[2/]	2.3	17.5	3.0
FortisBC Inc.[2/]	2.2	10.9	2.8
Hamilton Utilities	3.4	32.0	4.7
Hydro One Inc.	3.2	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	26.1	5.7
Maritime Electric	2.5	12.9	2.6
Newfoundland Power [2/]	2.4	14.0	2.9
Nova Scotia Power	2.4	14.2	3.3
Toronto Hydro	2.7	17.5	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	12.5	3.0
Gaz Metropolitain	2.5	24.0	4.6
Pacific Northern Gas [4/]	2.4	26.4	3.2
Terasen Gas	2.0	9.7	2.4
Union Gas [3/]	2.1	12.8	2.8
Pipelines			
Enbridge Pipelines [3/]	3.3	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	15.7	2.8
Westcoast Energy Inc.	2.1	16.4	3.1
Medians			
Electric T&D	**2.7**	**17.5**	**3.8**
Electric Integrated	**2.5**	**14.2**	**3.3**
All Electric	**2.6**	**17.5**	**3.5**
Gas Distributors	**2.1**	**12.8**	**3.0**
All Companies	**2.4**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P						Average ROE
			Average 2004-2006				
Name	**Debt Rating**	**Business Profile**	**Debt Ratio**	**EBIT Coverage**	**FFO/Debt**	**FFO Coverage**	**2004-2006**
Alabama Power Co.	A	4	54.3	4.3	22.8	5.6	13.5
Central Hudson Gas & Electric Corp.	A	3	66.3	4.7	16.7	4.3	12.2
Consolidated Edison Co. of New York Inc.	A	2	54.8	2.8	18.7	3.9	10.0
Consolidated Edison Inc.	A	2	57.2	2.6	16.7	3.7	9.2
Duke Energy Carolinas LLC	A-	4	48.0	4.0	28.8	14.9	NA
Duke Energy Corp.	A-	5	48.7	3.2	19.8	3.9	9.9
Duke Energy Indiana Inc.	A-	4	56.7	3.1	17.6	4.6	8.8
Duke Energy Ohio Inc.	A-	5	38.7	4.5	23.2	5.6	11.0
Florida Power & Light Co.	A	4	41.1	5.9	34.1	7.7	11.7
FPL Group Inc.	A	5	51.8	2.7	22.3	4.5	12.4
Georgia Power Co.	A	4	56.0	4.6	22.0	6.1	14.1
Gulf Power Co.	A	4	54.5	3.7	20.9	4.6	12.2
Integrys Energy Group Inc.	A-	5	58.6	3.4	13.8	4.1	12.5
KeySpan Corp.	A-	3	61.8	3.5	16.2	3.9	10.4
Madison Gas & Electric Co.	AA-	4	52.4	4.5	20.4	5.1	10.6
MidAmerican Energy Co.	A-	5	52.4	4.4	26.0	5.8	14.2
MidAmerican Energy Holdings Co.	A-	4	74.9	1.9	11.1	2.5	13.2
Mississippi Power Co.	A	4	63.0	4.2	22.8	10.8	13.9
NSTAR	A+	1	65.4	3.5	22.6	4.9	13.3
NSTAR Electric Co.	A+	1	49.7	5.7	39.4	8.1	13.8
Orange and Rockland Utilities Inc.	A	2	70.8	3.6	16.9	3.9	NA
PacifiCorp	A-	5	59.0	2.5	15.0	3.7	7.0
PPL Electric Utilities Corp.	A-	3	51.0	3.1	26.2	4.9	NA
San Diego Gas & Electric Co.	A	5	54.8	5.0	25.9	6.7	16.3
SCANA Corp.	A-	4	57.6	2.5	22.5	4.2	11.4
South Carolina Electric & Gas Co.	A-	4	50.1	2.6	25.6	5.1	10.3
Southern Co.	A	4	57.0	3.8	22.3	5.3	14.9
Vectren Corp.	A-	4	60.4	2.7	15.9	3.9	10.5
Wisconsin Electric Power Co.	A-	4	52.5	4.8	25.0	6.8	11.8
Wisconsin Power & Light Co.	A-	4	48.1	3.6	31.1	5.9	9.9
Wisconsin Public Service Corp.	A	4	52.3	4.0	22.3	5.4	10.1
Mean	**A**	**4**	**55.5**	**3.7**	**22.1**	**5.5**	**11.8**
Median	**A**	**4**	**54.8**	**3.6**	**22.3**	**4.9**	**11.8**

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 1, 2007; *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest,* November 9, 2007; and *Credit Stats,* September 2007.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures (DBRS) Issuer (S&P)	A		A-	
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [2/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
TransCanada PipeLines	Senior Secured	A		A	Very conservative
	Senior Unsecured	A	A2	A-	
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Electric T&D		**A**	**Baa1**	**A-**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**BBB+**	**Very conservative**
All Electric		**A**	**Baa1**	**A-**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
All Companies		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

**CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)**

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd. [4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electric Utilities								
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55
ATCO Electric		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55
EPCOR		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55
FortisBC Inc.	3/06; 11/07	BCUC	G-14-06; L-93-07	60.00	0.00	40.00	9.02	4.55
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	6/06	IRAC	UE20934	57.31	0.00	42.69	10.25	na
Newfoundland Power	10/07	NLPub	Settlement Agreement	54.01	1.15	44.84	8.95	4.60 [1]
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na [2]
Northwest Territories Power Corp.	8/07	PUB of NWT	Decision 13-2007	52.26	0.00	48.59 [3]	9.25	4.60
Ontario Electricity Distributors	12/06	OEB	Report of the Board	60.00	0.00	40.00	8.98	5.00 [4]
Yukon Energy	10/05	YUB	OIC 1998/32; Order 2005-12, BCUC G-55-07	60.00	0.00	40.00	9.15	4.55 [5]
Gas Distributors								
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55
Enbridge Gas Distribution Inc	1/04; 7/07	OEB	RP-2002-0158; EB-2006-0034	61.33	2.67	36.00	8.39	4.23
Gaz Metropolitain	10/07	Régie	D-2007-116	54.00	7.50	38.50	9.05	4.78
Pacific Northern Gas	11/07; 5/07	BCUC	L-93-07; G-55-07	56.20	3.80	40.00	9.27	4.55
Terasen Gas	3/06; 11/07	BCUC	G-14-06; L-93-07	65.00	0.00	35.00	8.62	4.55
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23
Gas Pipelines								
Alberta Natural Gas	11/07; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.72	4.55
Foothills Pipe Lines (Yukon) Ltd.	11/07; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.72	4.55
TransCanada PipeLines	11/07; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.72	4.55
Trans Quebec & Maritimes Pipeline	11/07	NEB	RH-2-94	70.00	0.00	30.00	8.72	4.55
Westcoast Energy	11/07; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.72	4.55

[1] The settlement agreement specifying ROE and capital structure is subject to PUB approval.

[2] A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35% if approved.

[3] The capital structure of NTPC includes no cost capital (-.85%).

[4] The 8.98% is the return on equity that would apply at a forecast yield of 5.0% as per the Board's December 2006 report.

[5] The YUB sets YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Board Decisions.

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 25-2008 **October 27, 2008**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (NWT) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (NWT) Limited to their customers within the Northwest Territories, by seeking approval of the Phase 1 General Rate Application.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Joe Acorn	Chairman
	John Hill	Vice-Chairman
	William Koe	Member
	Sandra Jaque	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Loyola Keough	Counsel for Northland Utilities (NWT) Limited
Thomas Marriott	Counsel for the Town of Hay River
Rangi Jeerakathil	Counsel for the Hamlet of Fort Providence

WITNESSES

Northland Utilities (NWT) Limited

Jerome Babyn	General Manager
Duane Morgan	Manager
James Grattan	Manager, Pricing
David Freedman	Director, Regulatory
Kathy McShane	Consultant for Northland

Town of Hay River

Robert Bruggeman	Consultant for the Town of Hay River
William Marcus	Consultant for the Town of Hay River

Hamlet of Fort Providence

Azad Merani	Consultant for the Hamlet of Fort Providence

ABBREVIATIONS

Act	Public Utilities Act
AMR	Automatic Meter Reading
AUC	Alberta Utilities Commission
Board	Northwest Territories Public Utilities Board
BR	Board Information Request
CC&B	Customer Care and Billing
CEO	Chief Executive Officer
COLA	Cost of Living Adjustment
CRA	Canada Revenue Agency
CPI	Consumer Price Index
DB	Defined Benefit
DC	Defined Contribution
Ex	Exhibit
FMV	Fair Market Value
Fort Providence	Hamlet of Fort Providence
FP	Fort Providence Information Request
FTE	Full-Time Equivalent
GAAP	Generally Accepted Accounting Principles
GNWT	Government of the Northwest Territories
GRA	General Rate Application
Hamlet	Hamlet of Fort Providence
Hay River	Town of Hay River
HDD	Heating Degree Days
HR	Hay River Information Request
IFRS	International Financial Reporting Standards
IR	Information Request
IT	Information Technology
ITBS	Information Technology Billing Systems
I-Tek	ATCO I-Tek
kV	Kilovolt
kWh	Kilowatt-Hour
l.	Line
Northland	Northland Utilities (NWT) Limited
NTPC	Northwest Territories Power Corporation
NUL	Northland Utilities (NWT) Limited

NUY	Northland Utilities (Yellowknife) Ltd.
NWT	Northwest Territories
O&M	Operation & Maintenance
p.	Page
PUB	Northwest Territories Public Utilities Board
R.S.N.W.T.	Revised Statutes of the Northwest Territories
Test Years	2008/2010 test period
Town	Town of Hay River
Tr.	Transcript
UPC	Usage per Customer

TABLE OF CONTENTS

1. BACKGROUND & APPLICATION

By letter dated February 8, 2008, Northland Utilities (NWT) Limited (“**Northland**”, “**NUL**”) submitted to the Northwest Territories Public Utilities Board (“**the Board**”, “**PUB**”) a General Rate Application (“**GRA**”, “**Application**”) for the 2008/2010 test period (“**Test Years**”) (Ex. 2).

In its Application, Northland requested order or orders of the Board to:

a) Determine the Company’s rate base and revenue requirement for the forecast test years 2008, 2009 and 2010;
b) Continue utilizing 7 deferral accounts – Purchase Power Flow Through Deferral Account, Diesel Price Variances Deferral Account, Hay River Diesel Generation Deferral Account, Rainbow Capital Maintenance Expenditures Deferral Account, Tamerlane Ventures Inc. Industrial Sales Deferral Account, Defined Benefit and Contribution Pension Plan Cash Contribution Deferral Account and Income Tax Rate Variance Deferral Account.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated February 15, 2008 directed Northland to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notice provided details of the GRA and invited interested persons to file a request with the Board for intervener status (Ex. 1).

By letter dated February 20, 2008, the Hamlet of Fort Providence (“**the Hamlet**” or “**Fort Providence**”) registered their respective intervention with the Board. The Town of Hay River (“**the Town**” or “**Hay River**”) also registered their respective interventions with the Board, by letter dated February 22, 2008. Mr. Peter Redvers representing the Sambaa K'e Dene Band of Trout Lake indicated an interest in the proceeding, by submitting a request to intervene form to the Board office. The Northwest Territories Power Corporation (**"NTPC"**) also indicated an interest in the proceeding.

The Board, the Town, the Hamlet and NTPC submitted information requests, to which Northland responded on May 5, 2008 (Ex 3).

Northland submitted information requests to the Hamlet in regards to its intervener evidence (Ex. 4). The Hamlet responded to the information requests on June 12, 2008 (Ex. 5).

The Board and Northland submitted information requests to the Town in regards to its intervener evidence (Ex. 6). The Town responded to the information requests on June 12, 2008 (Ex. 7).

2. PUBLIC HEARING

Public Notice of the hearing was published in *the Hub* on April 2, 2008, April 9, 2008 and June 4, 2008 and in the *News/North* on March 31, 2008 and April 7, 2008 (Ex 1). The hearing was held in the City of Yellowknife on June 19, 2008 and in the Town of Hay River on June 25, 2008.

On June 19, 2008, the hearing for Northland was opened in Yellowknife to hear the witnesses on capital structure, rate of return equity and cost of debt. The hearing was adjourned in Yellowknife on June 19, 2008 and reopened in Hay River on June 25, 2008.

During the course of the hearing, members of the public who had not initially requested intervener status were invited to participate in the proceeding but there were no additional interveners identified.

The Board and all interested parties agreed to set July 21, 2008 for the written argument and August 1, 2008 for the written reply argument.

3. RATE BASE

The determination of the rate base, for the purpose of fixing just and reasonable rates, is governed by the provisions of Section 49 of *the Act*, which states:

> "49 (1) In fixing just and reasonable rates, the Board shall determine a rate base for the property of the public utility used or required to be used to provide service to the public within the Territories.
> (2) In determining a rate base, the Board shall consider
> (a) the cost of the property referred to in subsection (1) at the time that property was first devoted to public use, and to the prudent acquisition cost to the public utility, less depreciation, amortization or depletion; and
> (b) the necessary working capital of the public utility."

This section of the Decision examines the issues raised with respect to determination of NUL's rate base for the test years.

3.1 2007 Opening Balances

Fort Providence submitted that, as a matter of principle, where prior year actuals are available, the Board should use such actuals to determine the Test Year forecasts. In this case, the Board has available to it the 2007 actuals and, therefore, should direct NUL to include in its Refiling, a recalculation of the Test Year Revenue Requirement using the 2007 actuals.

Views of the Board

The Board agrees the best available information at the time of the hearing should be reflected in the test year forecasts. Accordingly, the Board directs NUL to reflect the 2007 actual plant closing balances in the plant opening balances for 2008 in its Phase 1 refiling.

3.2 Capital Additions

Capital additions were detailed in Section 9 of the Application and are forecast to be $1.990 million, $0.954 million and $1.536 million for the test years 2008, 2009 and 2010, respectively. This section of the Decision examines the issues raised with respect to capital additions to the rate base.

3.2.1 Forecast Accuracy

Hay River expressed concern over the different unit costs per lot related to the development of three subdivisions in the community. After being provided with additional information by NUL (Ex. 17) which explained those differences, Hay River stated in its argument that it was prepared to accept the differences in unit costs per lot for the three subdivisions.

Views of the Board

This matter was resolved among the parties and nothing further is required by the Board.

3.2.2 Customer Care and Billing System

NUL proposed to begin converting to a new billing system in 2007 with the project completed in 2008. NUL forecast costs of $81,000 in 2007 and $183,000 in 2008. While the old billing system continued to met NUL's basic needs, it was determined that the existing system would no longer be cost-effective due to the larger ATCO Alberta utilities migrating away from the existing system to a new ATCO system. ATCO's northern affiliates such as NUL would have been left to bear the full operating and maintenance cost of the old system.

Hay River was concerned about a lack of transparency by NUL in its decision to select and implement the new ATCO billing system over two competing products. However after reviewing additional information provided by NUL in its rebuttal evidence and examining NUL at the hearing, Hay River stated in its argument that it does not oppose the implementation of the new billing system and its inclusion in the rate base.

Views of the Board

The Board is satisfied that this matter was thoroughly examined and approves the addition of the new billing system to the rate base.

3.2.3 Fort Providence Generator Replacement

Fort Providence expressed concern in its argument about the timing of NUL's decision to refurbish diesel engine CUL 324 instead of replacing it, as it had received approval to do in the 2005-06 GRA.

> "Fort Providence notes the hearing of the 2005-2006 GRA was at the end of November 2005, at about the same time as NUL decided to refurbish engine CUL 324 rather than retiring it. It therefore knew, or should have known at the time of the 2005-2006 hearing there was no need to retire/replace CUL 324, as a major capital replacement. The result was recovery of capital-related costs of return, depreciation and income taxes in 2006 which it need not have recovered. Fort Providence submits it was

> incumbent on NUL to fully disclose all material facts it knew in respect of this matter at the time of the 2005-2006 GRA hearing. The result of NUL's non-disclosure of a material fact therefore led customers to unnecessarily pay for costs of capital replacement in Fort Providence.
>
> This type of non-disclosure by NUL is unacceptable. Although capital programs may change as test years progress, this is a different circumstance given the knowledge of NUL in late 2005. Fort Providence submits that the Board should specifically direct NUL with respect to future proceedings to disclose material changes in required capital expenditures which arise during a GRA proceeding. Full disclosure to customers and the Board is required for a fair hearing process. Otherwise, customers will end up paying for capital that is not in service or intended to be in service." (Fort Providence Argument, p. 30-31)

NUL also addressed this matter in its argument as follows:

> "During the Information Request process (FP-NWT-50), and again in cross-examination (1T234-241), Fort Providence raised questions regarding Northland's replacement of CUL-452. As indicated, Northland acted in a prudent manner with respect to the appropriate replacement of generation units required to provide safe and reliable service. Northland took advantage of recent manufacturer information regarding new technology available in the marketplace to refurbish unit CUL-324; and thereby optimize the use of existing units and minimize costs to customers. Northland also indicated that the lead time to obtain new units had increased materially due to the increase in demand experienced in recent periods. Northland adopted the best option available to provide safe and reliable service to Fort Providence." (NUL Argument, p. 18)

NUL addressed the matter again in its reply argument:

> "In its Argument (p. 30), Fort Providence attempts to create a wholly unsubstantiated impression that Northland did not behave in a prudent manner in the management and maintenance of the diesel generation units used to provide power to this community. Northland finds the submission of Fort Providence to be offensive, as the record clearly indicates that Northland at all times acted in a prudent manner to

ensure that power could be provided to Fort Providence in an economic, reliable and safe manner.

The evidence confirms that Northland responded to new information made available to it (1T 234-241; FP-NWT-50) and made the best decision regarding the provision of service to Fort Providence. The only evidence on the record confirms that, at all times, Northland acted in the best interests of its customers. Only those costs that were appropriately incurred regarding this project were charged to the project. Northland made the appropriate decision in the circumstances based on the new information that became available to it.

Northland submits that the inflammatory remarks of Fort Providence must be rejected out of hand. There is simply no support for these views."(NUL Reply, p. 24–25)

Views of the Board

The Board does not see anywhere that Fort Providence is questioning the prudence of NUL's decisions regarding the replacement vs. the refurbishment of the diesel engines. What Fort Providence is questioning is the timing of NUL's decisions and the lack of disclosure of those decisions during the 2005-06 GRA.

The Board agrees with Fort Providence that if NUL knew at the time of the 2005-06 GRA hearing that it was only going to refurbish CUL 324 and later on replace another engine, then it should have disclosed that information to the Board and interveners.

Although the Board does not see the need for a direction to be issued, the Board will state that it expects NUL to disclose any material change to its planned capital expenditures that occur during the course of a GRA review.

3.3 Contributions in Aid of Construction

In response to Hay River's evidence, NUL agreed to make corrections to contributions in aid of construction in its Phase 1 refiling.

Views of the Board

Subject to the necessary corrections, the Board approves the contributions in aid of construction for the test years as proposed by NUL.

3.4 Working Capital

NUL's calculation of necessary working capital for the test years is set out in Schedules 8.5 and 8.9 of the Application. To determine the working capital for the test years, a study was undertaken to determine the revenue lead lag days. This study was provided as Attachment 3 to Section 8 of the Application.

Fort Providence stated the following in its argument.

> "In Response FP-NWT-46 (a), NUL provided a revised computation of NWC to correct for certain errors related to the amount of income tax instalments, number of instalment tax lag days, tax receivable lag days, as well as common equity and depreciation lag days. Fort Providence has reviewed these corrections, and concurs with the revised Schedule 8.9 included as part of Response FP-NWT-46 (a) Attachment 1. While Fort Providence agrees with NUL the net impact of these corrections on the Revenue Requirements is not material, Fort Providence recommends the Board direct NUL to include these corrections in its Refiling Application for sake of completeness and clarity of record." (Fort Providence Argument, p. 55)

Views of the Board

The Board does not consider it necessary to issue a direction on this matter to NUL. The Board expects NUL will make all necessary corrections when it prepares its Phase 1 refiling.

The Board has not identified any concerns with the amount of working capital for the test years. Subject to any required corrections, the Board approves the working capital amounts for the test years as proposed by NUL.

4. RETURN ON RATE BASE

Having determined the rate base for NUL for the test years, the Board is required, pursuant to section 50 of *the Act*, to fix a fair return on the rate base.

Section 50 of *the Act* provides as follows:

> "50. (1) The Board shall fix a fair return on the rate base of a public utility.
> (2) In fixing a fair return, the Board shall consider all the facts that it considers relevant."

The Board's objective in fixing a fair return on rate base is to enable NUL to recover its cost of servicing those portions of the rate base financed by long and short term debt and to provide an opportunity to earn a fair return on the portion of rate base deemed to be financed by common equity.

4.1 Capital Structure and Return on Equity

Northland proposed a capital structure containing a common equity ratio of 50% in conjunction with an allowed return of on equity of 9.6% for the test period.

Ms McShane, expert witness for Northland concluded Northland was of higher than average business risk relative to the typical Canadian Utility. She indicated NUL's higher than average business risk relates to the very small size of the utility and the fact that it operates in a service territory with an undiversified economic base tied to a single industry and it faces significant physical/operating challenges. NUL noted the company's higher risk relative to its sister company NUY relates to its ownership of generation assets. Ms McShane noted that since NUL's debt is raised by CU Inc. NUL should contribute its fair share toward the maintenance of CU Inc's debt rating. Ms McShane indicated the common equity ratio that would fully compensate for Northland's higher business risk lies at the upper end of a range of 50.0% to 55.0%. Ms McShane arrived at her recommendations having regard to data from other electric utilities, rating agency guidelines and rating agency commentary.

Ms McShane did not recommend a move to the 55% equity ratio. She expressed two concerns with moving the common equity ratio to 55%. First, in her view, the shareholders considered the benchmark rate of return to be too low; therefore she questioned why they would want to invest additional equity in order to have the opportunity to earn an inadequate return. Second, in Ms McShane's view, requiring minority shareholders to make an equity infusion would create an additional level of risk to those shareholders. Accordingly Ms McShane recommended the benchmark rate of return on equity of 9.1% should be increased by 50 basis points to 9.60% rather than increasing the common equity ratio.

Mr. Marcus, expert witness for the Town recommended an equity ratio of 40 to 42% for NUL's operations – a figure that is, in Mr. Marcus' view, modestly but not inordinately higher than the benchmarks for large utilities in Canada, that is consistent with the OEB's determination for small electric distribution companies and consistent with the Alberta determination for AltaGas, also a small gas utility. Mr. Marcus submitted the Board should reject the increased return on equity recommended by Ms. McShane in lieu of a further increase in the equity percentage.

With respect to the separate systems operated by Northland, one being Northland Utilities (Yellowknife) Limited and the other being Northland Utilities (NWT) Limited, Mr. Marcus stated the Board should not be paying Northland

Utilities Limited more money just because it operates similar types of utilities in two different towns and raise the equity percentage further by considering that each individual utility is smaller than the entire Northland Utilities Limited system. Mr. Marcus stated it is unreasonable to balkanize the system in this way. Mr. Marcus did not see any reason why Northland Utilities Limited should be different than NTPC which is treated as a unified system. However, Mr. Marcus noted if the two utilities were not considered together, taking certain offsetting factors into account, NUL might have slightly more risk than NUY but these small differences are subsumed within the range of 200 basis points:

> "NUL NWT has slightly more cost risk because NUL-Yellowknife has a capital deferral account for the distribution system rebuild and there is no similar account for NUL-NWT. However the additional cost risk must be considered modest because NUL-NWT also does not have the large capital program to rebuild its distribution system that is covered by the deferral account in NUL-Yellowknife.
>
> NUL-NWT has somewhat more cost risk because it owns generation plants. However, generation risk is modest (considerably less than in other parts of the U.S. and Canada) because (1) the plants are diesel and are therefore less complex than thermal or hydro generation plants owned by other utilities and would also not have the cash flow or regulatory risk of a large central station generator accruing AFUDC until it comes into service, (2) plants in Hay River provide back-up service and are operated infrequently, thereby reducing both capital and O&M risks; (3) the cost of diesel overhauls is covered through reserve accounting in the remote communities where the plants are run more frequently; and (4) most importantly, there are no competitive generation options in the Northwest Territories.
>
> NUL-NWT has somewhat less demand risk than NUL-Yellowknife because the Yellowknife economy has more mining-related volatility, and loads have been more variable in Yellowknife. Per capita residential loads also have been decreasing in Yellowknife, unlike Hay River.
>
> Overall, if the two utilities were not considered together, taking these offsetting factors into account suggest that NUL-NWT might have slightly

more risk than NUL-Yellowknife but these small differences are subsumed within the range of 200 basis points presented by Mr. Marcus" (BR HR 1b)

NUL submitted looking only at the equity ratios adopted by regulators renders Mr. Marcus' analysis completely circular. Moreover, Mr. Marcus' analysis failed to take into consideration the following:

- The quantitative impact on capital structure of the additional fifty basis points in return on equity that the Board allowed NTPC
- Other relevant allowed capital structure benchmarks such as that of Newfoundland Power
- Any bond rating or interest coverage analysis
- Debt rating agency guidelines for capital structure
- The actual capital structure maintained by Canadian utilities
- Any relevant changes in income tax rates, allowed returns on equity or capital cost allowance rates since the 2004 Alberta Decision that have negatively impacted interest coverage ratios for the Alberta utilities used as benchmarks in his analysis

.

Views of the Board

The Board notes both NUL and the Town agree that NUL's business risks are somewhat higher than those applicable to an average electric utility primarily due to its small size and economic characteristics of the service area. However, they differ in their assessment of the extent to which the various risk factors contribute to NUL's overall business risk.

The Board agrees NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area. The Board notes Mr. Marcus' assessment NUL's business risks are somewhat higher than those of NUY.

In terms of peer comparisons, the Board notes the 41% equity ratio awarded by the AEUB to AltaGas, a gas utility that is of relatively small size although larger than NUL in terms of size. The Board also notes Newfoundland Power was awarded an equity ratio of 44.5% together with an equity risk premium of 0.15%. (Table 5 McShane Testimony) Maritime Electric was awarded 42.7% with an equity premium of 1.25% higher than the average Canadian utility. (Table 5 McShane Testimony) In reviewing peer comparisons, the Board is also cognizant of the impact of changes in tax and capital cost allowance rates on coverage ratios.

The Board notes the following coverage ratios for NUL for the years 2006 Actual and 2007 Forecast and for the forecast test years 2008 to 2010 under the proposed capital structure and proposed return on equity:

Table 1 NUNWT Proposed Coverage Ratios
($000s)

	2006A	**2007**	**2008**	**2009**	**2010**
Total Return	811	854	935	975	976
Income Tax	174	201	129	332	309
EBIT	985	1,055	1,064	1,307	1,285
Depreciation net of Amortization of Contributions	730	754	807	859	903
Funds from Operations	1,715	1,809	1,871	2,166	2,188
Debt Interest	420	430	420	390	390
Interest Coverage	2.35	2.45	2.53	3.35	3.29
FFO Interest Coverage	4.1	4.2	4.5	5.6	5.6

Note: Based on original filing

The Board notes from Table 1 NUL achieved interest coverage ratio of 2.35 and a funds from operations ("**FFO**") interest coverage of 4.1 in 2006. The Board recognizes that coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.

Having weighed all of the evidence, the Board considers that an equity ratio of 44% together with the benchmark return on equity of 9.1% would result in a fair return on rate base for NUL in 2008, 2009 and 2010 that is consistent with the company's investment risks. The resulting approximate coverage ratios are set out below:

Table 2-NUNWT Return on Rate Base
($000s)

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 Test Period				
Long-term debt	53.58%	6494	6.40%	416
Common stock	44.00%	5333	9.10%	485
Customer Deposits	1.02%	124	4.59%	6
No Cost Capital	1.40%	170	0.00%	0
Total	100.00%	12,120	7.48%	907
2009 Test Period				
Long-term debt	53.65%	6642	6.39%	424
Common stock	44.00%	5447	9.10%	496
Customer Deposits	1.05%	130	4.59%	6
No Cost Capital	1.30%	161	0.00%	0
Total	100.00%	12,380	7.62%	926
2010 Test Period				
Long-term debt	53.81%	6680	6.39%	427
Common stock	44.00%	5462	9.10%	497
Customer Deposits	0.89%	110	4.59%	5
No Cost Capital	1.30%	161	0.00%	0
Total	100.00%	12,414	7.70%	929

Table 3 Coverage Ratios Based on Board Approved Equity Ratio and ROE
($000s)

	2006A	**2007**	**2008**	**2009**	**2010**
Total Return	811	854	907	926	929
Income Tax	174	201	117	295	272
EBIT	985	1,055	1,023	1,221	1,201
Depreciation net of Amortization of Contributions	730	754	807	859	903
Funds from Operations	1,715	1,809	1,830	2,080	2,104
Debt Interest	420	430	421	430	432
Interest Coverage	2.35	2.45	2.43	2.84	2.78
FFO Interest Coverage	4.1	4.2	4.3	4.8	4.9

Note: Based on original filing

The Board notes the coverage ratios resulting from a 44% common equity ratio together with a 9.1% return on equity will be comparable to or higher than those achieved by NUL in 2006 and estimated for 2007. The Board notes the FFO interest coverage ratios in 2008, 2009 and 2010 of 4.3, 4.8 and 4.9 would be higher than those applicable to the average Canadian utility of about 3.8 times.(McShane Testimony, p. 29;*I.,* 762)

Accordingly, the Board determines a common equity ratio of 44% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

4.2 Cost of Debt

With respect to cost of debt NUL stated there are no new debt issues included in the filing. However, given that there could potentially be some debt issues as a result of this Board Decision, NUL agreed to use the debt rate approved by the Board in the NUY proceeding, should these circumstances arise.

Views of the Board

In light of the Board's determination on capital structure, the Board considers NUNWT may need to raise new debt within the test period. The Board considers that it would be appropriate for NUNWT to include any new debt at the cost rate for new debt approved for NUY in Decision 24-2008. NUNWT is accordingly directed to reflect this determination in its Phase I refiling application.

4.3 Customer Deposits

Fort Providence submitted inasmuch as customer deposits are used more for working capital purposes i.e. to fund shorter-term operational requirements rather than longer term capital requirements, it is inappropriate to consider these funds as part of NUL's capital structure. Fort Providence submitted the mid-year balance of customer deposits should be treated as a reduction to necessary working capital. In Fort Providence's view interest expense payable on customer deposits should not be allowed for recovery. However, Fort Providence submitted, interest amounts are fairly immaterial (at about $6,000 per year) and accordingly, if the Board is inclined to allow recovery of interest paid on customer deposits, such interest should be included in O&M expense rather than as return on rate base.

NUL noted customers requested the inclusion of customer deposit in capital structure to benefit from low cost financing. Including the interest expense on customer deposits in O&M expense would not result in any material change in revenue requirement.

Views of the Board

The Board considers it appropriate to include customer deposits and the financing costs associated with customer deposits in the capital structure. The Board does not accept Fort Providence's recommendations in this regard.

5. PURCHASED POWER, DIESEL FUEL AND LOSSES

5.1 Purchased Power

All of NUL's purchases of power are from the NTPC to service the Hay River area. The purchased power costs are outlined in Section 3 of the Application and total $2.235 million, $2.250 million and $2.262 million for each of the test years 2008, 2009 and 20210, respectively.

Hay River had no comments in its argument regarding purchased power expense.

Views of the Board

The Board has not identified any concerns with the purchased power expense for the test years. The Board approves the purchased power expense for the test years as proposed by NUL.

5.2 Purchase Power Flow Through Deferral Account

The costs of purchased power included in the Application are based on the NTPC's December 31, 2007 rates. NUL proposes that subsequent increases or decreases to those rates will be flowed through to NUL's customers using Rider F for the Purchase Power Flow Through deferral account and only as approved by the Board.

Hay River had no comments in its argument on the purchase power flow through deferral account.

Views of the Board

The Board has not identified any concerns with the proposed purchased power flow through deferral account. The Board approves the use of the deferral account as proposed by NUL.

5.3 Diesel Fuel Costs

Diesel fuel is purchased for each of NUL's five systems. The diesel fuel costs are outlined in Section 4 of the Application and total $1.552 million, $1.464 million and $1.313 million for each of the test years 2008, 2009 and 2010, respectively.

Every three years NUL conducts a fuel tendering process in which a vendor is selected to be the exclusive provider of fuel to NUL. Fuel costs are recorded as the diesel fuel is consumed by a diesel plant. For planning purposes, forecast diesel prices for each community for each of the 3 test years are based on a regression formula derived from the previous 48-months Edmonton Par Oil Prices and diesel rack prices.

Variances between the actual and forecast fuel prices are refunded to or recovered from customers through a diesel price fuel rider (Rider A), which is discussed in Section 5.4 of this Decision.

For the Hay River service area, variances between the forecast and actual fuel costs associated with the relative level of diesel versus hydro generation are refunded to or recovered from customers through the Diesel Generation Rider (Rider I), which is discussed in Section 5.5 of this Decision.

The only concern raised by Hay River in its argument with regard to diesel costs relate to NUL's proposed operation of the Diesel Generation Rider (Rider A) and so those concerns will be discussed in Section 5.4 of this Decision.

The only concern raised by Fort Providence directly related to the purchase of diesel fuel is the use of hedging. Fort Providence stated the following in its argument:

> "Due to the significant volatility in the price of diesel fuel, and considering the recent unprecedented increases in fuel costs in 2008, customers would have benefited from having a portion of the fuel supply locked in as hedged purchases. While Fort Providence recognizes this conclusion has the benefit of hindsight, these facts nonetheless demonstrate that a prudent fuel procurement management policy would, to the extent possible, include hedged purchases in addition to spot and near term purchases.
>
> Fort Providence notes the current contract with Petro-Canada is valid from October 1, 2006 to September 30, 2009. Fort Providence recommends the Board direct NUL, when it tenders its next fuel contract, to provide evidence that the vendors were asked to provide a pricing proposal which included hedging for a portion of NUL's fuel supply requirements and the responses from such vendors." (Fort Providence Argument, p. 13)

NUL responded in its reply argument as follows:

> "Fort Providence also recommended that Northland, in its next GRA, be required to provide evidence that vendors were asked to provide proposals which included hedging a portion of NUL's fuel supply requirements. Northland submits that such a direction is wholly unnecessary, as the evidence is clear on this matter. Northland achieves maximum economics of scale by combining its fuel purchases with those of ATCO Electric, but has confirmed that the volumes are too small to

> attract interest in any hedging proposal. Additionally, Northland has confirmed that the costs of such measures would not warrant their adoption. This direction is simply unnecessary and should not be imposed on Northland." (NUL Reply, p. 6-7)

Views of the Board

The Board accepts the argument of NUL and will not impose any direction related to hedging. However, the Board does expect NUL to always be aware of and open to the advantages of engaging in a hedging program should such a program be able to produce benefits for NUL's customers.

Given that in Section 5.5 of this Decision, the Board has rejected Hay River's proposed change to the Diesel Generation Rider, the Board approves the forecast diesel fuel costs for the test years as proposed by NUL.

5.4 Diesel Fuel Price Variances Deferral Account

The variances between actual and forecast diesel fuel prices are refunded to or recovered from customers through a diesel fuel price rider (Rider A) subject to Board approval.

Hay River and Fort Providence had no comments in their arguments on the diesel fuel price variances deferral account.

Views of the Board

The Board has not identified any concerns with the proposed diesel fuel price variances deferral account. The Board approves the use of the deferral account as proposed by NUL.

5.5 Hay River Diesel Generation Deferral Account

NUL proposes that the variance between the actual and forecast fuel costs associated with operating the Hay River generation facilities for a level of generation that is greater or less than 4.1% of total supply be recovered from or refunded to customers through the Diesel Generation Rider (Rider I) subject to Board approval. The use of 4.1% of total supply is based on the analysis provided in Section 4 Table 1 of the Application.

Table 1
Hay River Generation 2002 - 2006

Year	Total Purchase Power from NTPC (kWh)	Total Diesel Generation (kWh)	Total Supply (kWh)	Share of Diesel	Adjustment for Transmission & Substation Maintenance (kWh)	Adjusted Diesel Generation (kWh)	Adj. Share of Diesel
2002	31,262,000	1,309,456	32,571,456	4.0%	44,618	1,264,838	3.9%
2003	29,792,000	3,069,913	32,861,913	9.3%	221,330	2,848,583	8.7%
2004	32,830,000	898,255	33,728,255	2.7%	84,474	813,781	2.4%
2005	32,333,000	709,882	33,042,882	2.1%	94,300	615,582	1.9%
2006	31,262,000	1,377,387	32,639,387	4.0%	93,993	1,283,394	3.7%
			Average	4.4%		Adj. Average	4.1%

In its argument, Hay River stated:

> "As noted in Mr. Bruggeman's evidence, NUL itself used a 2.5% outage rate in the 2005/2006 GRA which would have implicitly included the 2003 outages. The 2003 outages are clearly anomalous and regardless of whether there is an arbitrary threshold value, should be excluded. Including an anomalous value to arrive at 4.1% for Rider I could lead to a 1% over recovery during each of the next three years followed by a 1% refund rider following the annual true up, all things equal. This would introduce unnecessary fluctuations in customers' bills. **The Town submits that Rider I should be determined based on 3.0% outages to the NUL supply with**

> **resulting reductions in fuel costs of $77,000, $71,000 and $62,000 respectively in the three test years."** (Hay River Argument, p. 5)

In its argument, NUL stated:

> "There is no contention that the numbers used by Northland to determine the 5-year average are in any way inaccurate. Rather, Hay River would arbitrarily eliminate one year on an indiscriminate basis. Hay River confirmed that it has no criteria or threshold that would be applied in a consistent manner (IT286). Northland submits that the Board should not accept Hay River's suggestion in this regard. To do so would abandon the underlying methodology and lead to suggestions that any particular year should be deleted if it does not fall within Hay River's unspecified threshold. Northland's approach is logical and consistent and the impact of fluctuations is smoothed out over time." (NUL Argument, p. 6)

Both Hay River and NUL addressed this matter again in their reply argument but no new additional information was provided.

Views of the Board

The Board agrees with Hay River that anomalous data can and should be removed from data sets for the purpose of making forecasts. However, the Board does not agree that this is such a situation. Even with the inclusion of the 2003 data, the 5-year average of 4.1% is still only slightly higher than the actual figures of 3.9% and 3.7% for 2002 and 2006, respectively.

The Board approves NUL's proposed use of 4.1% for diesel generation for the purpose of the Hay River Diesel Generation deferral account.

5.6 Diesel Fuel Efficiencies

NUL's plant efficiencies are based on the average of three years adjusted for the non-recurring use of less efficient units or for the forecast fuel efficiencies of any new engines forecast to be in service.

Hay River had no comments in its argument on diesel fuel efficiencies.

Fort Providence pursued three issues in its argument:

1) The Board should direct NUL in its next GRA to track and provide diesel fuel efficiencies on a per engine basis instead of just for each plant as a whole. NUL should also provide an assessment of the actual experienced fuel efficiency for each engine to that provided by the manufacturer and explain the differences, if any;
2) The Board should direct NUL in its next GRA to use the 3-year 3:2:1 weighted average method for calculate plant efficiencies that was approved in Decision 13-2007 instead of the simple 3-year average method being proposed by NUL; and
3) The Board should direct NUL in its next GRA to give due weight to earlier test year fuel efficiencies in forecasting later test year fuel efficiencies, as the Board directed NTPC to do in Decision 13-2007.

NUL addressed Fort Providence's 3 issues in its reply argument. On the issue of tracking engine efficiencies, NUL stated:

> "Northland is of the view that its current approach is a reliable and reasonable methodology to monitor plant performance and identify potential issues. If the Board were to agree with Fort Providence, that heat rates for each unit should be measured and monitored in the manner

suggested, Northland would need to install and monitor new fuel measurement devices for each of the diesel units, as well as potentially upgrade the energy generated meters for each of the diesel units, as it does not presently have heat rates by individual unit. While Northland would ensure that each of the new fuel gauges was properly engineered and installed, the additional fuel gauges would inherently introduce an ongoing added measure of spill risk, given that Northland would be cutting into fuel lines to install these devices. Northland is also of the view that the costs associated with these suggested measures certainly cannot be justified on the basis of any potential, marginal benefits that may be achieved. Northland monitors plant efficiency based on the above noted methodology. Anomalies are investigated, if and when they occur. Northland does not see the measures suggested by Fort Providence as being necessary or justified. As such, Northland submits that the suggestions of Fort Providence should not be accepted by the Board." (NUL Reply, p. 5-6)

On the second issue (3-year 3:2:1 weighted average), NUL stated:

"Northland disagrees that the 3:2:1 weighted approach would be more reflective of actual circumstances, as it does not reflect measurement issues between years that are addressed through the use of a three year average. Northland submits that its proposed approach is reasonable and consistent with past filings and should be accepted by the Board." (NUL Reply, p. 6)

NUL did not respond to the issue of giving due weight to earlier test years when forecasting fuel efficiencies for later test years.

Views of the Board

The Board will not accept Fort Providence's recommendation to direct NUL to track and provide fuel efficiencies on a per engine basis. While tracking fuel efficiencies on a per engine basis would produce more accurate data, the Board does not see that the benefits would outweigh the costs.

The Board is also of the view that it should not be approving different procedures and approaches for the different utilities unless there is a significant reason to do so. With regards to fuel efficiencies, the Board sees no significant reason for its treatment of NUL to differ from that of NTPC, which only provides fuel efficiencies on a per plant basis.

The Board does, however, see merit in the second half of Fort Providence's first recommendation concerning the manufacturer's engine efficiency ratings. By comparing the overall plant efficiency to the manufacturer's ratings for the individual engines within the plant, it will be more readily apparent if there are efficiency concerns within a particular plant that perhaps would justify undertaking a more detailed engine-by-engine evaluation of actual fuel efficiencies. The Board directs that, in its next Phase 1 GRA, NUL is to compare the overall fuel efficiency of each plant to the manufacturer's rated engine efficiency for each engine within that plant. If there are significant discrepancies between the overall plant efficiency and the individual rated engine efficiencies, NUL is to provide an explanation and potential solutions to improve plant efficiency.

The Board agrees with Fort Providence that the 3-year 3:2:1 weighted average method of calculating fuel efficiencies is superior to the 3-year simple average method proposed by NUL. Using this weighted system is more efficient at transferring benefits to the ratepayers as a result of technological and operational improvements and there are no significant barriers to its implementation. The Board directs that, in its next Phase 1 GRA, NUL is to calculate forecast fuel efficiencies using three years of data weighted 3 for the highest efficiency year, 2 for the middle efficiency year and 1 for the lowest efficiency year.

Given the generally upward trend in fuel efficiencies, it is the Board's view that calculating later test year forecasts without including the earlier test year forecasts could result in customers foregoing fuel efficiency improvements. The Board directs that, in its next Phase 1 GRA, NUL is to give due weight to earlier test year forecast fuel efficiencies when calculating the later test year forecast fuel efficiencies.

5.7 Losses and Station Service

In accordance with Board Direction No. 4 in Decision 9-2006, forecast line losses in each community were determined based on an engineering assessment of the level of line losses. The engineering assessment was included as Attachment 1 to Section 4 of the Application. NUL states in the Application that while high construction costs often negate positive net economic benefits, NUL continues to examine available and reasonable measures to reduce such losses.

NUL was examined on the issue of losses by the Board staff and Chair at the Hay River hearing. When questioned about the high losses due to the line between Dory Point and Kakisa, NUL stated:

> " MR. DUANE MORGAN: We have had a look at that line several times and are aware of the losses along there, you know, and know that they're -- they're higher than -- than what they are in other communities. And the 54 kilometres of single phase line add to that loss, as it says in the study there.
>
> We have had a look at the possibility of reconductoring or three-phasing, but just isn't economic for us to have a -- to go ahead and do that right now at this point so...
>
> The order of -- of magnitude that would impact on the customers there are certainly -- we don't think that -- yeah, yeah, we -- we did do an

> estimate of the -- of the additions to the live issue, was about --probably about in the magnitude of about three hundred thousand dollars ($300,000), in that area. So we just didn't feel it would be economic for us to do that." (Tr., p. 263, *l* 23 – p. 264, *l*. 14)

Board staff also questioned NUL about the station service in Trout Lake. NUL responded as follows:

> " MR. JAMES GRATTAN: And -- and the, I think one -- one thing that's important to -- to note is whether the -- the system loss in -- in Trout Lake is 13.9 percent, which is on Table -- Table 3.
>
> And I think one of the things that the company is trying to do is, in fact, confirm whether we've got the -- the relative mix between station service loss and the other components of loss in -- in the proper -- proper spots.
>
> So in total we've -- we've got a 13.9 percent loss in Trout Lake. The installation of the new meter will confirm whether, in fact, we do, in fact, as a subset of that 13.9, have a station service line loss of 5.8 percent or whether that loss is -- is somewhere else; whether, in fact, it's -- it's in station service or possibly if the -- if the measurement was -- was not accurate, whether it should be more appropriately classified in secondary distribution loss.
>
> But there would be no impact on the revenue requirement on a go-forward basis." (Tr., p. 267, *ll*. 1-20)

The Board Chair asked NUL about applying caps to losses and station, as the Board had done in Decision 13-2007 for the NTPC Phase 1 GRA.

> " MR. JEROME BABYN: I don't recall – I don't recall what NTPC had provided in the context of that hearing as it related to a study around losses. We -- we believe that we've complied with the Board directive given to us in '05 and '06, and we completed a study.
>
> I think we're fairly confident that the -- that the losses that exist in the communities are – are as we've shown here and that we demonstrated here.

> So -- so to -- to cap those losses, I guess, you know, would be, you know, something that, you know, I guess certainly is well within the Board's authority, I suppose, but certainly, you know, would -- would cause us concern that we weren't able to capture those costs, so..." (Tr., p. 271, *l*. 15 – p. 272, *l*. 4)

Hay River had no comments in its argument regarding energy losses.

In its reply argument, Fort Providence stated the following:

> NUL, in Argument[4], refers to the examination by Fort Providence on matters related to use of a "weighted three year average, versus a simple three year average for station service." The record will show this discussion was not related to the computation of station service costs, but rather the determination of heat rates.[5] However, Fort Providence notes that the 3:2:1 approach was also approved by the Board in Decision 13-2007 [page 71] in relation to the determination of station service for NTPC. Consistent with this Decision, it would appear logical for the Board to approve the use of this 3:2:1 approach for NUL's station service costs if it is inclined to approve this method for the derivation of heat rates.
>
> (Fort Providence Reply, p. 4)

Views of the Board

The Board notes that NUL includes station service in its engineering assessment of energy losses. The Board does not consider station service to be losses and would prefer to discuss losses and station service separately. However, as NUL has addressed both issues in its engineering assessment, combined with the uncertainty in Trout Lake over the relative amounts of station service and losses, the Board will deal with losses and station service together in this decision.

The Board directs that, in its next Phase 1 GRA, NUL is to provide separate analysis and discussions for losses and station service.

As with fuel efficiencies, the Board is of the view that it should not be approving different procedures and approaches for the different utilities unless there is a significant reason to do so. With regards to losses and station service, the Board sees no significant reasons for its treatment of NUL to differ from that of NTPC.

The Board is of the view that loss and station service data are similar to the use of fuel efficiency data in that the data sets are all measurements of the efficiency of a particular portion of the electrical system. Given that the data sets are all efficiency measures, it is the Board's view that losses and station service can and should be forecast with the 3-year 3:2:1 weighting procedure used for fuel efficiency forecasts. Using this weighted system is also more efficient at transferring benefits to the ratepayers as a result of technological and operational improvements.

While the 3-year 3:2:1 weighting system is preferred by the Board for dealing with losses and station service, the Board recognizes that this method might not be suitable for application to non-electrical losses. As well, the Board recognizes that there is insufficient evidence in this proceeding to effectively separate total losses into electrical losses and non-electrical losses.

The Board directs that, in the next Phase 1 GRA, NUL is to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.

The Board directs that, in the next Phase 1 GRA, NUL is to calculate station service using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” given to the middle station service year and a weighting of “1” given to the highest station service year. Consistent with its directions respecting fuel efficiencies, the Board directs that, in its next Phase 1 GRA, NUL is to give due weight to earlier test year station service forecasts when calculating the later test year station service forecasts.

The Board is also concerned about the total magnitude of losses and station service in the communities, particularly Kakisa/Dory Point. In Decision 13-2007, the Board decided that the NTPC communities needed to be protected from high losses and station service through the imposition of caps. Losses were capped at 7% and station service was capped at 5%. It is the Board’s view that the NUL communities deserve the same level of protection as the NTPC communities.

The Board directs that, in its Phase 1 refiling, NUL is to apply a 12% combined loss and station service cap as a percentage of generation.

6. OPERATION AND MAINTENANCE EXPENSES

Operations and maintenance ("**O&M**") expenses were dealt with in Section 5 of NUL's Application. NUL is seeking Board approval for O&M expenses of $3.303 million in 2008, $3.509 million in 2009 and $3.698 million in 2010.

Interveners raised various issues with respect to various aspects of O&M and these issues are discussed in the remainder of this section.

6.1 Inflation

6.1.1 Labour Inflation

NUL is forecasting labour inflation according to the following table.

	2008	**2009**	**2010**
Collective Agreement In-Scope	11%	5.25%	6%
Out-of-Scope	10%	6%	7%

The first two years for the in-scope employees is based on the collective agreement that was negotiated in 2007. The in-scope employees received an 11% increase in 2008 and a 5.25% increase in 2009. The higher increase in 2008 was due to an extra market adjustment that year. The 6% forecast for 2010 is based on expectations for a tight labour market.

Although not explained well by NUL, the out-of-scope increases for 2008 and 2009 appear to be based on amounts contained within the negotiated collective agreement. As for the in-scope employees, the 2010 increase for the out-of-scope employees is also based on the assertion of a continued tight labour market.

The Town dealt with this matter in its argument:

> The Town is prepared to accept the proposed wage increases for the in-scope group for 2008 and 2009 based on the collective agreement that was negotiated with those employees. However, there is no evidence on the record to support the 6% increase proposed for 2010 other than the anecdotal statement "to reflect an expected continued tight labor market." [21] Each of the groups making up the in-scope employees received 5.25% plus market adjustments in 2008 to bring wages into line with ATCO Electric. There is no evidence to suggest that the labor market will be even tighter in 2010 than it was in 2008 and further, the Consumer Price Index is forecast to remain relatively flat through 2013. Therefore, in-scope increases should be limited to no more than 5.25% in 2010.
>
> With respect to out-of-scope increases, the Town is prepared to accept the 10% increase in 2008 that brought this group up to market. However, there is no evidence to suggest that this group should be given an additional 1% over and above the in-scope group, notwithstanding the additional management responsibilities suggested by NUL during cross examination.
>
> **The Town submits that salary and wage increases should be limited to the following for purposes of this application:**

	2008	**2009**	**2010**
Collective Agreement In-Scope	**11%**	**5.25%**	**5.25%**
Out-of-Scope	**10%**	**5.25%**	**5.25%**

(Hay River Argument, p. 7)

In its argument, NUL stated:

> "…Northland submits that it is simply not reasonable to assume that in-scope employees will only require an increase of 5.25% in 2010 as part of the new Collective Bargaining Agreement. The average increase over the current two year agreement is 8.125% and, if anything, Northland's 2010

forecast of 6% can be considered as being modest in light of the continuing "hot" labour market that is forecast to continue in southern markets well past 201 0.

Likewise, Hay River's recommendation that the percent increase for out-of-scope employees for 2009 and 2010 be limited to the level set for in-scope employees is not fair or reasonable. During cross examination Hay River acknowledged that out-of-scope employees perform management functions and assume management responsibilities that are not assumed or performed by in-scope employees. Hay River also acknowledged that generally management employees have a higher pay than in-scope employees (1T291-292). Northland submits that the failure to recognize these differences will result in the pay scales of in-scope and out-of-scope employees being compressed, with the result that Northland would have considerable difficulty attracting the small number of out-of-scope employees required to run its company. Northland submits that the forecast inflation assumptions for labour contained in its Application are reasonable and should be approved by the Board, as filed." (NUL Argument, p. 7-8)

The Town responded to NUL in its reply argument:

"…The 11% in 2008 consisted of a market adjustment up to the level of ATCO Electric wages plus 5.25%. HR submits it is inappropriate to use the average of 8.125% which included a market adjustment. There is no evidence on the record that there will need to be another market adjustment in 2010 nor that the market will be even tighter in 2010 than it was in 2008. Further, as noted in Mr. Bruggeman's evidence, the CPI is forecast to remain relatively flat from 2008-2012. Finally, as noted in Mr. Bruggeman's evidence and in Argument, "he settlement package also provided for increases in the designated community allowance and one additional flight out of the north per year which translated to an additional 8.0% and 2.8% respectively on labor expenses.

NUL goes on at pages 7-8 to suggest that HR acknowledged that out-of-scope employees perform management functions and assume management responsibilities not assumed or performed by in-scope employees and that management employees have higher pay. NUL asserts that the failure to recognize these differences will result in compression of pay between in-scope and out-of-scope. HR addressed this in part in Argument at page 7 but would add the following. First, both groups were brought up to market in 2008 and therefore the relative levels

> of pay should be in line with duties in 2008. Second, given the higher pay levels for in-scope as noted by NUL in Argument, equal percentage increases in pay will result in the differentials widening rather than compressing." (Hay River Reply, p. 4-5)

In its reply argument, NUL again asserts that the Town is ignoring the 8.125% increase over the two-year agreement. NUL also states that it is not reasonable to assume that NUL will be able to conclude another agreement at the same level as the last year of the previous agreement. NUL argues that demands for and compensation paid to skilled employees have increased. NUL also repeats its argument that holding the out-of-scope employees to the same increase as the in-scope employees would result in compression issues that would make it difficult to attract and retain the necessary management resources.

Views of the Board

The Board agrees with the Town that NUL has not provided the evidence to justify the forecast 6% increase for in-scope employees in 2010. The Board also finds NUL's use of the 8.125% average increase over the two years of the agreement to be misleading due to the market adjustment in 2008. NUL has not provided sufficient evidence that another such adjustment will be required or that an increase above 5.25% is required for 2010.

For the out-of-scope employees, the Board also agrees with the Town on the issue of salary compression. The same percent increases for out-of-scope and in-scope employees will result in the salary gap between these employees widening, not compressing. NUL has not justified the 2009 and 2010 increases for the out-of-scope employees being higher than the in-scope employees.

The Board directs that, in its Phase 1 refiling, NUL is to use the following inflation amounts for employees:

- In-scope 11% in 2008, 5.25% in 2009 and 5.25% in 2010
- Out-of-Scope 10% in 2008, 5.25% in 2009 and 5.25% in 2010

6.1.2 Other Inflation

NUL is forecasting an inflation rate of 5% for “Other” O&M expenses. Hay River argues that simply applying a single inflation rate to all “Other” expenses results in an overestimate of the inflation rate for certain components of “Other”. Hay River argues that operating materials and supplies plus the non-affiliate and non-contractor costs should be inflated using the March 2008 Statistics Canada Consumer Price Index (CPI) of 3.2% instead of the 5% used by NUL.

In its argument, NUL states that its experience regarding things such as material and supplies and contractor services is that the inflation rate has been at levels far above the 5% forecast for NUL and that the forecasted 5% is necessary to cover costs.

Hay River replied by explaining that its recommendation of a 3.2% inflation rate is only for specific components of “Other”, not “Other” as a whole. Hay River reiterates that it recommendation is for operating material and supplies plus the non-affiliate and non-contractor costs.

NUL replies that it appears that the Hay River recommendation is focused on items which would have a very small impact on NUL’s operations and that the bulk of material costs have far exceeded that 5% inflation rate forecast by NUL.

Views of the Board

The Board finds that NUL has not adequately provided a response to Hay River's recommendation and appears to be confusing matters by bringing into the discussion items that would not be impacted by Hay River's recommendation.

In the absence of reasonable evidence to the contrary, the Board finds that the 3.2% inflation rate from the March 2008 CPI is a valid measure of increasing costs for NUL. The Board directs that, in its Phase 1 refiling, NUL is to apply an inflation rate of 3.2% to operating materials and supplies plus the non-affiliate and non-contractor costs.

6.2 Labour

6.2.1 Vacancy Rates

NUL has applied a vacancy rate of 2.9% (0.5 FTE) to all labour expenses. Due to compensation changes, NUL has been able to reduce its vacancy rate from what it would have been and states that a vacancy rate of 0.5 FTE is consistent with Board Decision 9-2006 and reasonable for the purposes of this Application.

Hay River argued as follows:

> NUL provided the forecast and actual FTE's, Headcount and vacancies in HR-NWT-19(d) Attachment 1. The vacancy rate over the period 2004-2007 averaged 6.2% based on FTE's and 6.7% based on Headcount or about one vacant position each year. [23] This compares to the 0.5 FTE vacancy rate approved by the Board in Decision 9-2006. Although NUL continues to suggest that the vacancy rate should be approved at 0.5 FTE, the evidence is that over the last 4 years, NUL has simply not been able to achieve that. **The Town submits that the vacancy rate should be set at one FTE until such time as NUL demonstrates that it can achieve a lower vacancy rate.** Based on 16.5 FTE's [24] and the total labour expense, [25] a 1.0 FTE vacancy rate translates to $50,000, $53,000 and $56,000 in the test years.
>
> (Hay River Argument, p. 8)

Fort Providence also argued for an increase in the forecast vacancy rate:

> "In an environment where the labour force is fairly mobile, there is no guarantee NUL's forecast 2.9% vacancy rate will prevail throughout the 3-year Test Period. Fort Providence submits that no basis exists to conclude that NUL's 2008-2010 experience will be any different than the historical experience. As noted previously, in the period 2001-2004, there was a vacancy rate of 7.2% or 1.05 FTE; in 2005-2007A period, the average was 5.53% or about 0.94 FTE (5.53% *17 FTEs). Fort Providence recommends that the Board approve the long term average vacancy rate for the period 2001-2007A, of approximately 0.94 FTEs, for the Test Years. This would result in a reduction of about $36,000 in each of the Test Years." (Fort Providence Argument, p. 16)

NUL addresses this matter in its reply argument as follows:

> When one looks at the number of current vacancies, Northland confirmed that, since the last quarter of 2007, it has no vacancies. Northland has implemented new programs that are designed to attract and retain employees and is of the view that such programs will enable it to keep the vacancy rate at or below the forecast level of 0.5 FTE for the Test Period.
>
> (NUL Reply, p. 19)

Views of the Board

While the recent historical vacancy rate has hovered around 1.0 FTE, the Board is of the view that NUL's forecast vacancy rate of 0.5 FTE is not unreasonable given the improvements that have been made to employee compensation and benefits combined with the current vacancy rate of 0 FTE. The Board will not direct NUL to increase its forecast vacancy rate from 0.5 FTE.

6.2.2 Employee Expenses

In Schedule 5.2 of the Application, NUL forecasts employee expenses of $206,000, $213,000 and $219,000 for test years 2008, 2009 and 2010, respectively. The increased costs are attributed to changes in employee family mixes and the extra flight per year for employee out of the North.

However, in IR response FP-NWT-35(b), NUL reduces these expenses by $69,000, $73,000 and $77,000 to produce new test year expenses of $137,000, $140,000 and $142,000.

NUL stated the following in its argument:

> In his evidence, Mr. Bruggeman noted that employee expenses were forecast to increase from $149,000 in 2007 to $206,000, $213,000 and $219,000 in the test years. [46] The reasons given were changes in family mixes and the additional flight out per year. NUL provided the incremental costs for the additional flight out of the north in HR-NWT-19(c) Attachment 1. NUL revised employee expenses in FP-NWT-35(b) Attachment 1 and indicated that the revenue requirements would be reduced in a compliance filing. **The Town has no further issue with employee expenses and the cost of the extra flight per year and expects to see reductions of $69,000, $73,000 and $77,000 for the test years in the compliance filing.**
>
> (NUL Argument, p. 13)

Neither NUL nor Fort Providence addressed this matter in their argument.

Views of the Board

The Board has not identified any concerns with the employee expenses for the test years. Subject to the correction identified in IR response FP-NWT-35(b), the Board approves the employee expense for the test years as proposed by NUL

6.2.3 Community Allowances

In the Application, NUL explained that it has implemented a new designated community allowance of 15% with a forecast cost of $185,000, $195,000 and $206,000 for test years 2008, 2009 and 2010, respectively.

However, NUL later determined that the community allowance was supposed to have been 10% for trade employees only instead of 15% for all employees. As part of its rebuttal evidence, NUL provided an updated response to IR FP-NWT-20(c)(iii) which reduced the community allowance expense by $116,000,

$122,000 and $129,000 to produce revised test year forecasts of $69,000, $73,000 and $77,000 for 2008, 2009 and 2010, respectively.

Hay River stated the following in its argument:

> NUL also noted in its Opening Statement that it had updated the costs for Community Allowances; [47] expenses were reduced by $116,000, $122,000 and $129,000 respectively in the three test years. **The Town has no further issue with Community Allowances as updated and expects to see those reductions in the compliance filing.**
>
> (Hay River Argument, p. 13)

Fort Providence stated the following in its argument:

> "In Fort Providence's view, the evidence is not conclusive on the need for the entire 10% community allowance, and why such a major component of employee compensation did not form a part of the 2008-2009 collective agreement. In the absence of such evidence, Fort Providence submits there is no basis to approve the proposed 10% community allowance in full. In recognition of the need to retain trades employees, and consistent with the Fort Providence recommendation in respect of vacancy rates, we recommend the Board approve half, or 5% of the community allowance, resulting in a decrease in the Revenue Requirement of $34,500 in 2008, $36,500 in 2009 and $38,500 in 2010." (Fort Providence Argument, p. 19)

NUL responded to Fort Providence in its reply argument:

> In this regard, Fort Providence recommends an arbitrary reduction of 50% in the community allowance requested by Northland (p. 20). There is absolutely no evidence to support such action. In fact, it is contrary to the only evidence, which clearly demonstrates the ongoing challenges faced by a small and remote utility such as Northland in attracting and retaining key employees. As indicated, Northland has implemented these measures in an effort to remain competitive in the marketplace. The positions advanced by Fort Providence are simply not responsible and, if adopted, would hamper Northland's efforts to attract and retain necessary employees. The recommendation of Fort Providence is unsubstantiated and should be rejected by the Board.
>
> (NUL Reply, p. 8)

Views of the Board

The Board will not reduce the 10% community allowance as recommended by Fort Providence. The Board agrees with NUL that in a competitive labour environment, NUL needs to be able to provide a sufficient level of employee benefits to be able to attract and retain employees. The Board expects that the effectiveness of the community allowance, as well as a discussion of whether or not the allowances should be eliminated, decreased or increased can be examined as part of the next Phase 1 GRA.

6.2.4 Other Earnings

In its response to IR FP-NWT-20(c), NUL identified its “Other Earnings” forecasts of $70,000, $81,000 and $93,000 for test years 2008, 2009 and 2010, respectively.

Fort Providence stated the following in its argument.

> “According to NUL, the foregoing payments are primarily for “standby pay for our trades people who are on call on a 24/7 basis.” No further details are provided as to why NUL needs costs in the Test Years which are significantly in excess of the amounts experienced in prior years. It would appear NUL would need to pay less in standby salaries under conditions where it is fully staffed as opposed to where it is not, as was the case in 2006-2007.
>
> Based on the foregoing, Fort Providence recommends the escalation in respect of “other earnings” should be scaled based on the collective agreement i.e. 11% in 2008 and 5.25% in 2009 and a further 6.0% in 2010 as follows:

Summary of Actual and Forecast "Other Earnings" - Salaries and Wages
Scaled based on Collective Agreement for 2008-2009; & NUL FC for 2010 re in-scope employees

	Source	2005	2006	2007	2008	2009	2010
Other Earnings, per NUL	X3, FP-NWT-20 (c)	$ 51,000	$ 54,000	$ 55,000	$ 70,000	$ 81,000	$ 93,000
Per Fort Providence							
2008 Escalation Factor	11.00%				61,050		
2009 Escalation Factor	5.25%					64,255	
2010 Escalation Factor	6.00%						68,110
Increase (decrease) $ in Revenue Requirement					**(8,950)**	**(16,745)**	**(24,890)**

(Fort Providence Argument, p. 20-21)

NUL responded to Fort Providence in its reply argument:

> In its Argument (p. 21) Fort Providence suggests that there is "no evidence" to support the significant increase in Other Earnings for the Test Years and recommends that the amounts forecast be "scaled back". These costs relate to stand-by costs for key employees and are absolutely mandatory in order to provide reliable and emergency service. Coverage is required on a 24/7 basis and the associated costs cannot be avoided. The increase in these costs reflect not only the influctionary pressures in labour but also the fact that new apprentices need to be trained regarding the roles and responsibilities they assume when on stand-by. In order to obtain such training, apprentices accompany a lineman on call from time-to-time to acquire the necessary and critical troubleshooting skills.

(NUL Reply, p. 20)

Views of the Board

The Board finds that NUL has provided a satisfactory explanation for the increased “Other Earnings” forecasts and the Board will not reduce the forecasts as recommended by Fort Providence.

6.3 Affiliate Costs

6.3.1 Information Technology Billing System Services

NUL receives Information Technology services ("**IT**") and Information Technology Billing System services ("**ITBS**") from ATCO I-Tek ("**I-Tek**") an affiliate of NUL. The terms under which NUL and other ATCO Utilities receive services from I-Tek are governed by a Master Services Agreement between I-Tek and the various ATCO Utilities.

The prices for IT and ITBS services paid by NUL and other ATCO utilities for the period 2003 to 2007 were the subject of a collaborative benchmarking process before the Alberta Utilities Commission ("**AUC**"). The prices determined in the benchmarking process were then adjusted pursuant to an Evergreen Strategy Report to arrive at IT and ITBS prices for 2008 and 2009 for the various ATCO Utilities. The prices for 2008 and 2009 determined under the Evergreen Strategy Report have not received approval by the AUC and are currently before the AUC for approval.

Having regard to the results of the Evergreen Strategy Report, NUL updated the placeholder amounts regarding IT and ITBS costs it had initially filed for the test years 2008 to 2010 by way of Exhibit 12, Response to HR-NWT11 b). Since 2010 is not covered by prices under the Evergreen Strategy Report, the prices for 2010 in the update reflect NUL's estimates of cost increases for IT and ITBS services in 2010. NUL stated it no longer sees the need for these updated amounts to be placeholders. This will avoid the need for any further regulatory processes relating to these costs.

Fort Providence submitted for a system with about 2,700 customers, the I-Tek affiliate charges amount to about $29.63/customer/year. Fort Providence noted this cost does not include capital-related costs related to the billing system, nor customer care functions such as handling customer inquiries. While the $29.63/customer/year may be a reasonable metric, there is no evidence from the company how this compares to an outsourced service. Nor is the company able to confirm or deny whether a company the size of NUNWT would typically engage in outsourcing its billing function. Fort Providence submitted NUNWT should be directed to provide evidence, at its next GRA, to demonstrate the reasonableness of this cost.

Hay River noted the revised I-Tek costs are down 4% on average and the revised I-Tek Business Services costs are down 9% on average.

Hay River submitted based on a 2007 FMV rate of $132.37 per month for laptop hardware operating lease, the updated amounts in HR-NWT 11(b) Attachment 1, reflect reductions of 3%, 4% and 0% in 2008, 2009 and 2010. Hay River submitted there should also be a 4% reduction in 2010

Hay River submitted PC Hardware operating leases were forecast to decline 3% to 5% in the Evergreen Report. Based on 2007 FMV rate of $74.26 per month, the reduction reflected in the updated amounts in HR NWT 11b) Attachment 1were by 3%, 4% and 0% in 2008, 2009 and 2010. Hay River submitted there should also be a 4% reduction in 2010.

Hay River submitted server storage was forecast to decline by 25% per year in the Evergreen Report and based on the updated amounts, declined by 25%, 25% and 0% in 2008, 2009 and 2010. Hay River submitted there should also be a 25% reduction in 2010.

Although the revised IT amounts filed in HR NWT 11b) Attachment 1 tend to more or less comport to the Evergreen Report, Hay River noted that the Evergreen Report will be subject to review in AUC Application No. 1577426 29 and the initial filing of the Application is now not expected to occur until August 29, 2008. Under these circumstances, Hay River submitted that the IT placeholders as updated in the Rebuttal Evidence should remain as placeholders until the AUC finalizes the Evergreen Applications.

With respect to base billing services, Hay River stated it appears that NUL has applied inflation to determine the 2008 and onward fees for Base Billing Service based on negotiations with ITBS which is contrary to the findings of the Benchmarking Report. Hay River submitted that the FMV charge for Base Billing Services should be $1.52 per site per month.

Hay River submitted the company has forecast base billing volumes of 34152, 34552 and 34906 sites in the test years. The company has also forecast 31872, 32268 and 32616 customer months. Hay River submitted the company should not be paying its ITBS monthly site charges if meters are not connected to the system. Hay River submitted the base billing volumes should be reduced to reflect the number of customer months.

With respect to Fort Providence’s comment respecting the overall reasonableness of charges, NUL submitted the annual charges of $75,000 in 2008, 82000 in 2009 and $82000 in 2010 are extremely reasonable when one considers that the hiring of a single accounting clerk to manage approximately 2900 meter reads a month, 2900 bill calculations a month, 2099 envelopes and stamps a month, processing of 2099 payments a month as well as daily, weekly and monthly balancing and controls. Edits and validations would be impossible to facilitate, especially when one factors in the additional complexities of maintaining a database for cost of service and rate design associated with multiple customer classes in five rate zones.

With respect Hay River's recommendation that there should be a 4% reduction in 2010 for laptop operating leases and PC operating leases, NUL stated the Evergreen Report does not indicate that decreases will continue indefinitely and Hay River's assertion is not supportable.

With respect to server storage in 2010, NUL stated the best information available to NUL is that price would remain flat for 2010.

With respect to increases to Oracle Financial hosting, NUL indicated labour charges are not the only factors driving the increases. The increases are also caused by items such as increased storage requirements as well as planned upgrades. It would therefore be inappropriate to restrict the increases to labour inflation only.

With respect to Hay River's suggestion that the prices be placeholders until AUC approval, NUL stated information regarding these costs have now advanced to the point where they can and should be finalized in the context of the current GRA. This would avoid costs associated with further regulatory process and allow these matters to be finalized.

With respect to the base billing services charge, NUL stated the $1.52 recommended by Hay River represents a five year rate established in 2003, which was not inflated over that time period. In the Evergreen strategy report, it is stipulated cost of living adjustment ("**COLA**") was not applicable to customer care and billing ("**CC&B**") services. Contracts for CC&B services tend to be for terms of five years and the proposed $1.72 per site per month billing services charge is a fixed price for 5 years. NUL indicated it has negotiated a new contract in 2008 which limits COLA adjustments to the labour components of services.

With respect to the discrepancy between base billing volumes and the number of customer months, NUL explained the difference is attributable to street and sentinel lights that are not detailed in Schedule 2.1 of the Application, as well as a small number of meters that have not been physically removed from premises due to the expectation they will shortly be back in service with either the same customer or a new customer.

Views of the Board

The Board has examined the argument of Hay River and NUL respecting the costs for laptop and PC hardware operating leases in 2010 and server storage in 2010. The Board accepts as reasonable NUL's explanation for not giving effect to further reductions in 2010 following the reductions to these costs in 2008 and 2009.

With respect to Oracle financial hosting, the Board notes NUL's explanation that the increases are caused by labour cost increases, increased storage requirements as well as planned upgrades. While these explanations appear satisfactory for 2008 and 2009 which years are supported by the Evergreen Report, the Board is concerned by the 16% increase in Oracle financial expense in 2010 over 2009. The Board has not seen convincing evidence to show why a 16% increase is warranted in 2010 following a 12% increase in 2009. The Board considers that a 3.2% increase in 2010 for Oracle financial hosting would be more in line with general price increases. Accordingly, the Board directs NUL to limit the increase in the Oracle Financial expense to 3.2% for 2010 and reflect this finding in the refiling application.

With respect to the base billing charges, the Board notes the $1.72 per site per month is a flat rate charge applicable over a five year period. The Board considers the use of a flat rate over the 5 year period results in a degree of front end loading of costs in the early years of the 5 year period and is not consistent with the principle of matching each year's costs with the corresponding recovery. Accordingly, for regulatory purposes, the Board considers each year's charge should reflect the escalation applicable to that year, rather than the average for the 5 years. The following table shows how the 5 year charge of $1.72 may be adjusted so that each year's charge reflects the escalation applicable to that year.

Escalation	5%
2008	1.56
2009	1.64
2010	1.72
2011	1.80
2012	1.89
Average	1.72

NUL is directed to escalate the base billing charge using a rate of 5% over the 5 year period so that the average of the rate over that period amounts to $1.72 and, to reflect this change in the refiling of the application.

The Board accepts NUL's explanations concerning discrepancy between base billing volumes and the number of customer months

Subject to the above noted changes, the Board accepts the remaining updated IT and ITBS charges for the test period.

6.3.2 Regulatory and Financial Reporting

Hay River identified the regulatory Phase I and financial reporting charges from ATCO Electric, to be as follows:

	$000
2004A	173
2005A	215
2006A	204
2007A	210
2008F	271
2009F	275
2010F	276

Hay River noted from NUL's evidence that these charges are based on the level of support for the 2008-2010 GRA, the anticipated 2011 filing and increased financial reporting charges; the estimated time is amortized over the three year period and translates to 1.8 FTE's per year.

Hay River submitted that the previous GRA filing was quite similar in that it involved preparation of the 2005/2006 GRA, the preparation of the current GRA during 2007 and financial reporting; however the costs increased from an average of $210,000 per year to an average of $274,000 over the three test years or +30%. Hay River submitted based on 10% wage increases in 2008 and 5% in each of 2007 and 2009, ATCO Electric is still charging some 36% more time to NUL. Although financial reporting requirements have increased in recent years the CEO/CFO certification began in 2005 and implementation was largely completed by 2007. Hay River submitted these types of costs may be replaced by things like introduction of International Financial Reporting Standards ("**IFRS**").

Hay River submitted that Regulatory Phase I and Financial Reporting costs included in NUL's forecast revenue requirement should be reduced by $29,000 in 2009 and $28,000 in 2010.

NUL submitted the charges by Regulatory Phase I and Financial Reporting, which are basically performed by the same staff, have been estimated based on the level of support required over the entire test period. The main filings are the 2008-2010 GRA as well as support required for the 2011 filing.

NUL submitted this estimated time to support these filings is then amortized evenly over this three year test period to avoid undue rate spikes in any given year. This estimate has resulted in approximately 1.8 FTEs being allocated to NUL during the test period.

NUL submitted that the level of financial reporting support is increasing with the upcoming changes to IFRS. NUL submitted, given that the current regulatory workloads include this GRA, as well as support for the 2011 GRA, and increased financial reporting requirements, the regulatory Phase I and financial reporting charges in the test period are reasonable.

Views of the Board

The Board notes NUL's evidence that the level of financial reporting support is increasing which includes the upcoming changes to IFRS. Having regard to the workload in the 2008 to 2010 period the Board accepts NUL's forecast of Regulatory Phase I and Financial Reporting costs for purposes of this Decision.

6.4 Head Office Costs

In Schedule 5.3 of the Application, NUL forecasts head office costs of $378,000, $387,000 and $396,000 for test years 2008, 2009 and 2010, respectively.

Fort Providence stated the following in its argument

> "Given the significant component of the HO costs in the Revenue Requirement, one must ask the question if these services are (a) prudently and necessarily incurred and (b) properly priced. NUL asserts it is difficult to recruit staff in the north, and that it considers it receives significant value in respect of the services received from HO. While this may all be true, the fact is that no evidence, by way of an independent external study exists, to support NUL's assertions.
>
> AE has recently filed a Stand Alone Study before the Alberta Utilities Commission. Fort Providence submits a study similar to the AE Stand Alone Study, would be useful to the Board and intervenors in the assessment of the prudence and reasonableness of the HO costs now being incurred by NUL. Such a study would review the HO costs provided by AE to NUL, and provide an assessment of the costs of these services if NUL were to source these services internally and/or from another independent third party. The Board should direct NUL, at its next GRA, to provide such a study." (Fort Providence Argument, p. 22)

NUL responded to Fort Providence in its reply argument.

Northland submits that such a study is absolutely unnecessary and would in fact be wasteful. The Head Office work for Northland is performed by a total of 2.3 FTEs. (Application, Section 1, Attachment 2). Northland has detailed above the scope and extent of the work performed by these people and it is clear that no third party could provide such services at anywhere near the current costs. As well, Northland derives significant benefits from its parental affiliation, such as taking advantage of all the work done by ATCO Electric on the benchmarking collaborative process. Similar benefits will accrue to Northland because of ATCO Electric's involvement in the IFRS issue.

The costs to conduct such a third party study would far outweigh any resultant benefits. Northland submits that the suggestion of Fort Providence should be rejected by the Board.

(NUL Reply, p. 21)

Views of the Board

The Board will not direct NUL to conduct the study as recommended by Fort Providence. The individual components of head office costs can be and are tested as part of the GRA and there has not been a demonstrated trend of excessive costs that would warrant the time and expense of conducting the recommended study.

6.5 Overhead Rate

The calculation of the 60% overhead rate applied on services rendered by ATCO Electric to NUL is shown in IR response FP-NWT-27(a) Attachment 2.

ATCO Electric
Overhead Rate

		Cross Ref	2007	2008
			$Millions	
Total Administration & General				
Account	Description			
859	Transmission miscellaneous		4.2	4.3
	Transmission IT Support		1.2	1.3
879	Distribution miscellaneous		14.1	14.9
	Distribution IT Support		4.0	4.4
70	Account Services &public info. (excluding 70100)		2.2	2.3
72	Common Operations		4.7	5.9
72	Corporate Admin		27.0	28.2
	Less:			
	Rate Hearing (not part of overhead rate)		(1.1)	(1.1)
	Affiliate Cost of Goods Sold		(1.0)	(1.1)
			55.3	59.1
Total Labour				
	Transmission		27.0	29.5
	Distribution		60.0	68.0
	Corporate		7.3	7.9
			94.3	105.4
Overhead Rate			58.64%	56.07%
General Recovery of Corporate GP&E				
	Corporate GP&E		13.1	12.9
	Return/Tax/Depn Rate		13.08%	12.93%
			1.7	1.7
			1.81%	1.59%
Total Overhead Rate			**60.46%**	**57.66%**

Fort Providence states the following in its argument:

> "Fort Providence submits while the overhead rate charged by NUL may be in accordance with the AE's Affiliate Code of Conduct, a 60% rate appears to be high. NUL has adduced no evidence to support what is included in the various A&G accounts noted in the above table, nor is there evidence on the appropriateness of including some of the A&G cost items in the numerator.

> The Board also has no evidence to collaborate the reasonableness of a 60% overhead rate i.e. if it is reasonable in light of what other service providers may be including. Evidence in this respect would provide additional comfort to the Board and intervenors on the reasonableness of the 60% rate by reference to external benchmark(s).
>
> Based on the foregoing, Fort Providence recommends the Board direct NUL to provide, at its next GRA, sufficient and appropriate evidence to support the amounts included in the various components that go into the make up of the AE corporate OH rate, and provide relevant external benchmarks to support the reasonable of the AE OH rates." (Fort Providence Argument, p. 25)

NUL responded to Fort Providence in its reply argument:

> Northland notes that the appropriate level of overhead costs that is to be charged by ATCO Electric to all affiliates is tested and approved by the Alberta Utilities Commission. ATCO Electric must act in accordance with the provisions of the ATCO Group Affiliate Code of Conduct and cannot reduce or vary the overhead rate charged for any individual entity – regulated or unregulated.
>
> Northland notes that the overhead rate has actually declined from 70% to 60% for the Test Years. Northland considers that the positions being advanced by Fort Providence are again unnecessary and excessive. An independent third party review is already occurring via the Alberta Utilities Commission review. The positions put forth by Fort Providence should be rejected by the Board.
>
> (NUL Reply, p. 21)

Views of the Board

The Board will not issue a direction to NUL on this matter. At the time of the next GRA, Fort Providence will be able to request the evidence that it feels is necessary through the IR process. Fort Providence would also be able to file with the Board the outcome of the independent third party review that is occurring before the AUC or any other comparative evidence to demonstrate why the 60% overhead rate appears high.

6.6 Rate Case Costs

NUL has estimated a $500,000 cost for the current GRA (Phases 1 and 2). Combined with the remaining balance of $199,000 from the previous GRA, the total rate case cost of $699,000 results in a 3-year amortization of $233,000 per year with no balance remaining at the end of 2010.

The $500,000 estimate for the current GRA is based upon the $433,000 cost for the previous GRA with additional costs for expert cost of capital evidence, extra costs for preparing a sales forecast study and reduced costs for no depreciation study.

During cross-examination by Hay River, NUL confirmed that its costs for legal counsel would be in the $600/hour range and its costs for the cost of capital expert would be in the $300/hour range. NUL also indicated that its cost for legal counsel for the previous GRA was about $130,000.

Hay River stated the following in its argument:

> While the Town is aware that the Board does not have a formal scale of costs, Decision 15-2007 suggests that the Board may have a de facto reasonable limit for the hourly rates for expert consultants. The Town notes that the two hundred fifty dollar ($250) per hour rate imposed by the Board in Decision15-2007 is the same level currently in force in the Alberta Utilities Commission's Scale of Costs as set out in its Rule 022 for both consultants and senior counsel. While recognizing that the AUC's scale of costs is under review and appears to be significantly out of date, the Town expects that the Board may consider legal costs in the $600 per hour range to exceed what is just and reasonable.
>
> NUL pointed out that the forecast in question is a "true-up account" [55] and the Town certainly acknowledges that. However, the Town would point out that historically, although the Board has afforded utilities the opportunity to comment on cost claims submitted by intervenors, the reverse has not been the case. Further, it is trite that a true-up account should be as accurate as possible, to minimize the magnitude of any eventual adjustment.
>
> **Accordingly, in light of the evidence on the forecast hourly rates for NUL's legal counsel and consultants, and in recognition of the Board's statutory discretion over costs, the Town recommends that this forecast be decreased to $400,000 from the $500,000 forecast by NUL The Town has no concerns regarding NUL's proposed equal amortization of these costs over the three test years but would recommend that the amount to be amortized be set at $400,000 plus the unamortized balance from previous proceedings. The Town would also recommend that in the interests of equitable treatment, the Board afford it an opportunity to comment on the cost claim submitted by NUL, just as it has historically given the utilities the opportunity to comment on the cost claims submitted by intervenors.**
>
> (Hay River Argument, p. 16)

NUL responded to Hay River in its reply argument:

> "While Hay River acknowledges that the Board does not have a formal scale of costs, it nonetheless arbitrarily seeks to deprive Northland of the

costs reasonably incurred for the conduct of its GRA. Northland would observe that it conducts its GRA with the assistance of a single legal Counsel and, with the exception of an expert witness on capital structure/rate of return in this case, does not engage any outside consultants for any other aspect of its Application. Northland's use of experienced Counsel at prevailing market rates is reasonable and appropriate and the arbitrary reduction recommended by the City is simply not supportable.

Northland would also note that Hay River's recommendation would reduce the level of rate case costs below those incurred for the 2005-2006 GRA (see Hay River Argument, p. 14). Given the additional matters pursued in this case, including the presentation of expert evidence, this is clearly not a reasonable position.

Additionally, Hay River's recommendation that it be afforded an opportunity to comment on the cost claim submitted by Northland is absolutely unnecessary. The Board should employ its normal process for the consideration and processing of cost claims and there is simply no reason to change the Board's traditional approach in the context of these proceedings." (NUL Reply, p. 17-18)

Views of the Board

The Board finds the rate paid by NUL to its legal counsel to be excessive, particularly when considering the amount of revenue requirement and the level of complexity of NUL's GRA.

Section 26 of the *Act* is clear that the Board has full discretion over the level of costs in relation to a proceeding.

> 26. The costs of and incidental to a proceeding before the Board or any investigation made by the Board, including the costs of an interested person, are in the discretion of the Board and the Board may order by whom, to whom in what amount the costs are to be paid.

As noted by Hay River, while the Board does not have a formal scale of costs, the Board did indicate a level of costs ($250/hour) that it considers reasonable in Decision 15-2007. However, the Board is also aware that the AUC has recently issued an updated schedule of costs (Rule 009) which caps legal fees at $350/hr and expert fees at $270/hr. The Board accepts that these rates might be more reflective of the current market conditions than the $250/hr used by the Board in Decision 15-2007.

While the Board agrees that the $100,000 reduction recommended by Hay River appears to be arbitrary, when requested NUL did not provide the evidence required for Hay River to have prepared a non-arbitrary recommendation.

The Board directs that, in its Phase 1 refiling, NUL is to use a forecast cost for the current Phase 1 and 2 GRA that is the greater of the following 2 options:

1) the $433,000 cost of the previous GRA; or
2) an updated forecast cost of the current Phase 1 and 2 GRA with rates for NUL's legal counsel capped at $350/hr and the cost of capital expert capped at $270/hour.

If NUL proceeds with Option 2, then it will be expected to provide supporting evidence and calculations.

While the Board considers the above direction to a fair and reasonable balance of interests that will be applied to the current GRA, it is clear that the Board will need to develop a formal scale of rates to avoid such situations in the future.

The Board also agrees with Hay River that it would be fair for the interveners to have the opportunity to comment upon cost claims by NUL and other utilities regulated by the Board. To formalize such a procedure, the Board will be required to make an amendment to its *Rules of Practice and Procedure*. However making this change will not be sufficient for this proceeding. The Board directs that, within 90 days of the conclusion of the Phase 1 and Phase 2 GRAs, NUL will file a cost claim with the Board covering both Phase 1 and 2.

6.7 Pension Expense

NUL participates in both of the Canadian Utilities-sponsored pension plans: Plan 1 is a combined Defined Benefit ("**DB**") and Defined Contribution ("**DC**") plan (which is the plan NUL's parent ATCO Electric operates). NUL participates in the DC portion of plan 1. Plan 2 is a DB pension plan and NUL participates in this plan.

Plan 1, the combined DC and DB pension plan, is currently in a surplus position, and as there are no funding requirements, there is currently a "pension holiday" i.e. there is no requirement to fund this plan using the cash method employed by NUL and ATCO Electric. Plan 2 was in a pension surplus position as at December 31, 2003 i.e. the last actuarial evaluation date, but is now in deficit position based on the most recent December 31, 2006 actuarial evaluation. The next such evaluation must be undertaken no later than December 31, 2009. NUL proposed a 27% funding requirement for Plan 2 for 2008, 2009 and 2010.

With respect to Plan 1, Fort Providence submitted the DC plan in Plan 1 is based on "Alberta-based employees". As there are no Alberta-based employees on the company's payroll, Fort Providence questioned why NUL needs to have a DC plan which is co-mingled with the DB Plan under Plan 1. Fort Providence submitted that unlike the funding requirements of the DB Plan, a DC plan's funding requirements are based on the employer and employee contributions, not on actuarial valuations. To avoid customer rates being subject to changes in funding requirements based on actuarially-determined values of DB-based pension plan assets and liabilities in Plan 1, Fort Providence recommended the Board direct the company, at its next GRA, to address the continued appropriateness of being under the parent company Plan 1, which combines DC and DB Plans. Fort Providence submitted the company should address why it cannot offer the DC plan on a stand alone basis, so that it is not tied to the performance and results of the DB Plan in Plan 1.

With respect to Plan 2, Fort Providence did not object to the 27% funding rate for 2008 and 2009. However, since there will be an actuarial evaluation of the DB Plan 2 no later than December 31, 2009, Fort Providence submitted that any funding assumptions for 2010 are premature and therefore the pension expense for 2010 should be set to zero as a placeholder.

With respect to Plan 1, NUL submitted Northland received the benefit of the surplus in ATCO Electric's DB Plan 1 by way of a contribution holiday but the DC plan (Plan 1) will not have to fund any more than the 6% requirement should there no longer be any surplus in Plan 1.

With respect to Plan 2, NUL stated while the actuarial evaluation will be done for 2010 there is no expectation the funding requirements will be reduced for 2010.

Views of the Board

Based on NUL's explanation, the Board is satisfied neither the Plan 1 DC plan nor the customers of NUL will be disadvantaged if there is a funding shortfall within the DB component of Plan 1. With respect to Plan 2, the Board notes NUL's assertion there is no expectation the 27% funding level will be reduced in 2010. Accordingly the Board will not accept the Hamlet's recommendations respecting the appropriateness of a combined DC and DB Plan 1 and the pension expense for 2010.

6.8 Defined Benefit and Contribution Pension Plans Cash Contribution Deferral Account

NUL stated the following in Section 1 of its Application:

> Beginning in 2010, Northland is seeking a deferral account to flow through increases or decreases to required cash contributions to the company's defined benefit and contribution pension plans. The timing of this request is based on the need for an updated actuarial valuation for pension funding for the year beginning January 1, 2010. In addition, Northland is proposing this deferral account flow through the impact, if any, the 2010 pension valuations will have on the affiliate labour expense charged for Whitehorse and Alberta based support services. The details of this deferral account are discussed in Section 5.

The Interveners did not raise any concerns with this proposed deferral account.

Views of the Board

The Board has not identified any concerns with the proposed deferral account. The Board approves the use of the Defined Benefit and Contribution Pension Plans Cash Contribution Deferral Account as proposed by NUL.

7. DEPRECIATION

Depreciation is discussed in Section 7 of NUL's Application. NUL forecasts depreciation expenses of $960,000, $961,000 and $1,009,000 for test years 2008, 2009 and 2010, respectively.

NUL proposed to continue using the existing depreciation rates for the test period. No issues were raised by Interveners respecting depreciation.

Views of the Board

The Board accepts NUL's proposed method of calculating depreciation for the purposes of this Decision.

8. INCOME TAXES

8.1 Income Tax Rate Variance Deferral Account

Fort Providence submitted NUL's 2008-2010 tax calculation reflects the use of the most recently enacted federal and territorial statutory corporate income tax rates. Fort Providence noted NUL proposes an income tax deferral account commencing 2008 only for changes in the enacted federal and territorial income tax rates, but not for any other tax-related changes

Fort Providence submitted based on Mr. Merani's evidence filed in these proceedings, there is sufficient evidence and grounds for directing NUL to set up a deferral account, effective January 1, 2008, to account for all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) from those reflected in the determination of the Test Year Revenue Requirements. Fort Providence submitted a similar deferral account has been approved for ATCO Electric by its regulator. Fort Providence submitted neither NUL shareholders nor customers should be at risk for changes arising from legislation related to income taxes as these changes are beyond the control of utility management

NUL submitted there are no proposed income tax changes that are not substantially enacted which are expected to occur during the test period. Further, NUL noted, even if CCA changes that have been around for a considerable period of time were implemented during the test period the result would be de minimus.

Views of the Board

The Board notes NUL has proposed an income tax deferral account for changes in income tax rates. This means NUL would be shielded from any gain or loss resulting from changes in statutory income tax rates with respect to the test period. Since a deferral account for income tax rates has already been proposed by NUL, including all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the deferral account would be consistent with the purpose of the income tax deferral account proposed by NUL. Accordingly, the Board directs NUL to include all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the income tax deferral account.

8.2 Deductions

Fort Providence submitted the Canada Revenue Agency ("**CRA**") has allowed immediate tax deductions in respect of certain capital repair costs which, for accounting purposes, are capitalized under Canadian GAAP, but which may be claimed as immediate tax deductions. Such tax deductions are generally referred to as "Rainbow-type" tax deductions.

Fort Providence submitted certain capital repair costs such as system performance improvements are being expensed by NUL for accounting purposes as well as for tax purposes whereas this type of expenditure should be capitalized and claimed as Rainbow-Type deductions for tax purposes. Fort Providence submitted, if material, such expensed capital repair costs could result in large swings in O&M expenses, making comparability over time more difficult.

Fort Providence submitted the Board direct NUL to cease its practice of expensing capital-repair costs. Fort Providence submitted these costs should be capitalized and treated as being eligible for the Rainbow tax deductions as part of the GRA Refiling.

Fort Providence also submitted it is difficult to believe NUL does not, or will not, treat as Rainbow-Type deductions for tax purposes certain expenditures which are taken as deductions for tax purposes by NUL's parent ATCO Electric. These expenditure items are as follows:

(i) Pole Treatment
(ii) Street Light Painting
(iii) Line Moves
(iv) Planning
(v) Cathodic Protection
(vi) System Performance
(vii) Life Achievement
(viii) Replacement
(ix) Safety and Environment
(x) External Requirements
(xi) Emergency Apparatus
(xii) Mitigate Equipment Problems

With respect to other Rainbow-Type deductions, NUL stated the company examines the Rainbow criteria to assess whether any of its projects qualify for such deductions as part of preparing for its filing. Further study is therefore not required. The majority of NUL's capital costs are for new extensions and distribution improvements. NUL submitted, in its view these expenditures are of an enduring benefit to the system and are being treated appropriately by NUL. NUL stated further, since line moves are 100% covered by contributions there is no issue respecting deduction of these items as Rainbow-Type deductions.

Views of the Board

With respect to capital repair costs, no evidence identifying the amount of capital repair costs that should be capitalized has been provided. The Board notes NUL has in fact identified certain deductions for Rainbow-Type expenses in calculating income taxes. Therefore, the Board will not accept Fort Providence's recommendation respecting capital repair costs for purposes of this Decision. With respect to other Rainbow-Type deductions, the Board accepts NUL's explanation that it examines the Rainbow criteria to assess whether any of its projects qualify for such deductions as part of preparing for the filing. The Board will therefore not require NUL to undertake a further study of expenditures eligible for Rainbow-type deductions.

8.3 Rainbow Capital Maintenance Expenditures Deferral Account

NUL stated the following in Section 10 of its Application:

> As directed by Board Decision 9-2006 Direction 10, Northland has reviewed its 2008-2010 transmission and distribution capital maintenance expenditures to determine whether the expenditure meets the criteria laid out in the Rainbow tax case for immediate tax deduction. Northland has forecast rainbow deductions of $21,000, $22,000 and $23,000 for the years 2008, 2009 and 2010 respectively. Please refer to line 21 on Schedule 10.1. These deductions relate to transmission and distribution pole test and treat expenditures that are capitalized for accounting purposes but deducted for taxation purposes.
>
> Northland is seeking approval to continue a deferral account for rainbow capital maintenance expenditures. The tax deferral account takes the form of refunding to or collecting from customers the differences between the placeholder amounts on Line 21 of Schedule 10.1 and the actual amounts claimed as tax deductions.
>
> Northland would like to point out that any subsequent disallowances of the actual filing deductions by CRA would result in Northland recalculating the deferral amounts for the year(s) in question and collecting the resulting difference from customers. Any interest and penalty amounts levied by CRA would also be collected from customers.

Hay River and Fort Providence had no comments in their arguments on the deferral account.

Views of the Board

The Board has not identified any concerns with the deferral account. The Board approves the use of the Rainbow Capital Maintenance Expenditures Deferral Account as proposed by NUL.

8.4 ES&G Charges

8.4.1 Stock Handling Charges

Fort Providence recommended the Board direct NUL to include in its refiling the incremental ES&G amounts related to the stock handling charges as additional tax deductions for the Test Years 2008-2010. In addition, Fort Providence submitted NUL should be directed to refile its prior income tax returns in respect of stock handling charges and flow the resulting tax savings to customers in its next GRA.

With respect to the Fort Providence's submission that NUL be directed to refile its prior income tax returns in respect of stock handling charges and flow the resulting tax savings to customers in its next GRA, NUL submitted the Hamlet's suggestion amounts to retroactive ratemaking which is not permissible.

Views of the Board

The Board notes NUL's treatment of stock handling charges, for income tax purposes, was different prior to the current test period. Prior to the current test period, stock handling charges were not deducted for calculation of the income tax component of revenue requirement, both in the forecasts and in the actuals. As long as NUL's treatment of stock handling charges remains consistent for the forecasts as well as actuals, the Board considers customers will not be harmed. However, if NUL were to choose to follow the route of ATCO Gas and request that its prior year income taxes be reassessed by CRA to the maximum extent possible including deduction for stock handling charges then customers will be harmed if such charges were not flowed through to customers.

In view of the foregoing, the Board will not direct NUL to retroactively adjust its deductions for stock handling charges respecting prior years. However, if NUL were to choose to request such deductions from CRA respecting prior years, the Board expects that any resulting income tax savings will be flowed through to NUL's customers.

8.4.2 ES&G Capitalization Policy

Fort Providence submitted in 2007, NUL incorporated a change in accounting policy as a result of which the salaries of persons working directly on capital projects, presently charged to ES&G for administrative ease, will no longer be included in ES&G. Fort Providence stated that while NUL does not address why the amounts of ES&G were not impacted, it is of concern that in future years, there may be a significant reduction in the ES&G tax deductions otherwise available with the adoption of the new policy.

Fort Providence submitted NUL has provided no evidence in support of its proposed change to company policy. More specifically, the practice of charging engineering support staff labour costs which cannot be identified with any particular capital work order has been in place to date, and there is no indication that the CRA has rejected any claims so made.

NUL submitted the advice from its tax experts within the ATCO Group is that the policy of charging to ES&G those people who work directly on capital projects, but for administrative ease were charging to ES&G, would not fall within the realm of what is allowable from a CRA perspective.

Views of the Board

The Board notes NUL's argument that the change in ES&G capitalization policy is due to the change in the previous practice of charging salaries of individuals who work directly on projects but for administrative ease were charging to ES&G. Under the new practice the salaries of such individuals would be charged directly to capital projects. The Board accepts NUL's explanation for change in ES&G capitalization policy for purposes of this Decision.

9. SALES AND REVENUE FORECAST

The sales forecast by customer class is provided in Schedule 2 of NUL's Application. NUL is forecasting total energy sales 36,053 MW.h, 36,320 MW.h and 36,545 MW.h for test years 2008, 2009 and 2010, respectively.

9.1 Sales Forecasts

The residential sales forecast is obtained by multiplying the forecast number of customers by the average usage per customer ("**UPC**") forecast.

NUL indicated the number of customer additions includes all known residential property developments and are based on discussions with developers and municipal/community planners within each community. NUL stated information regarding mine openings/closures in the NWT is also considered to identify potential customer additions/losses.

NUL used the 2006 temperature normalized UPC for all communities, with the exception of Dory Point, to arrive at the residential energy sales forecast for the test period. For Dory Point, the energy sales forecast is based on the three-year historical average UPC (2004-2006), as there is a very weak correlation between average UPC and HDD.

The commercial energy forecast is calculated by multiplying the customer count forecast by an average historic monthly consumption per customer. The energy forecast is calculated by multiplying the customer count forecast by the three-year average (2004-2006) historic monthly consumption per customer.

NUL indicated it relies heavily on information collected from its customers, the communities and local developers to determine the number of commercial customer additions expected in the forecast period. The customer forecast for the test period is then created based on the expected additions.

The energy forecast for street and sentinel lighting is based on a three-year historic average of light additions and a three-year historic average monthly consumption per type of light. NUL indicated the forecast also considers projects identified for the coming years.

With respect to the residential customer forecasts, the Hamlet submitted the residential customer growth rate for the community of Fort Providence should be increased to 1.73% for 2010:

> "Fort Providence submits there is no evidence to rely on in support of the 1.1% increase in the forecast number of customers in 2010. Using the 10-year average does not give recognition to recent history; as such, in the absence of any better information, Fort Providence recommends using an average of the 3, 5 and 10 year as well as the proposed 2008-2009 average i.e. 1.73%..." (Fort Providence Argument, p. 53)

The Hamlet also submitted that the Fort Providence 2007 normalized usage per customer (UPC) of 5467 kWh/customer rather than the 2006 UPC of 5331 kWh/customer should be used to calculate the residential sales.

With respect to commercial sales, the Hamlet submitted the three year normalized average UPC, including 2007, should be used to calculate the commercial UPC for the community of Fort Providence for purposes of forecasting commercial sales.

In response to the Hamlet's comments respecting the residential customer forecasts for Fort Providence, NUL submitted for 2008 and 2009 the company has forecast customer growth of 3.9% and 2.3% respectively. The average annual proposed growth rate is 2.4% for the period 2008-2010. This exceeds the historical average growth rate of the 3, 5 and 10 year averages. Further 2007 shows a customer growth rate of 0.8% for Fort Providence.

With respect to the residential UPC for Fort Providence, NUL indicated 2006 UPC was used for purposes of residential forecasts because it was the latest year for which full year data was available at the time the forecast was prepared. NUL stated its proposed forecast provided a higher residential average UPC than the three year historical average used in the past.

With respect to the Hamlet's concerns respecting commercial sales forecast for Fort Providence, NUL submitted it is inappropriate to use normalized commercial sales for determining the historical average use because of the low correlation between temperature and average use.

Views of the Board

With respect to customer growth rate in 2010 for Fort Providence, the Board accepts as reasonable NUL's explanation that the average annual proposed customer growth rate is 2.4% for the period 2008-2010 and this exceeds the historical average growth rate of the 3, 5 and 10 year averages. Accordingly, the Board does not accept the Hamlet's proposal to adjust the Fort Providence customer growth rate for 2010.

The Board notes the Hamlet's concern that the more recent UPC information for 2007 has not been reflected in the residential sales forecasts. The Board considers the best information at the time of the hearing should ideally be used to establish forecasts.

The Board notes there is relatively low correlation between UPC and temperature in most communities as reflected in relatively low R squared values in the regression studies (Section 2 Attachments 1-19) The following table shows there is a fair amount of variation in normalized average residential UPC from year to year:

Northland Utilities (NWT) Limited
Normalized Average Billed UPC by Customer Class and Community
(MW.h)

Residential	2003	2004	2005	2006	2007
Wekweti 904	6,167	6,255	6,145	6,091	5,401
Trout Lake 907	4,894	4,628	5,039	5,098	4,817
Hay River (Enterprise) 908	6,648	6,072	6,396	5,965	5,746
Hay River 910	6,789	6,573	6,742	6,647	6,691
Hay River (Dene) 911	8,533	8,347	8,381	8,353	8,179
Ft Providence 912	5,544	5,249	5,199	5,338	5,467
Dory Point 913	7,276	6,943	6,284	8,163	6,301
Kakisa 914	5,470	5,510	5,526	5,514	5,087

Source: FP NWT 9b-iii Attachment 1

Having regard to the variation in normalized average UPC, and in the absence of any specific reasons for such variations, the Board considers it more appropriate to use a 3-year average of normalized UPC including 2007, for purposes of the residential sales forecast as opposed to using a single year (2006), as proposed by NUL. Accordingly, NUL is directed to adjust its residential sales forecast for the test period to reflect the three year average normalized UPC from 2005 to 2007, for all communities, for purposes of the refiling application. For the community of Dory Point, because of the extremely low correlation between UPC and temperature, NUL is directed to use the 3-year average UPC including 2007 for purposes of the refiling application.

The Board agrees with NUL that it is not appropriate to use normalized commercial UPC for purposes of determining the commercial sales forecast due to the low correlation between commercial UPC and temperature. However, the Board considers the most recent information respecting commercial UPC should be reflected in the calculation of the commercial sales forecast. Accordingly for the purposes of determining the commercial sales forecast for all communities NUL is directed to use the three year average commercial UPC including 2007. To be consistent, NUL is also directed to use the 3-year average lighting usage per type of light including 2007, for the purposes of determining the lighting sales forecast for all communities. NUL should reflect these directions in its refiling Application.

9.2 Tamerlane Industrial Sales Deferral Account

NUL indicated although the company does not currently have an industrial customer, an approved industrial customer rate or an approved industrial customer investment level, it has been in discussions with Tamerlane Ventures Inc. ("**Tamerlane**") regarding the provision of electrical service to Tamerlane's property at Pine Point.

NUL stated, further to these discussions, the company has completed preliminary engineering work for a new substation that is required to serve Tamerlane and applied in August of 2007 for a franchise to serve Tamerlane.

NUL indicated over the coming year, the company expects that it will continue to work with Tamerlane, as well as the Government of the Northwest Territories and NTPC, to firm up the forecast billing determinants that would be required to develop and submit an industrial rate as well as investment level to the Board for approval.

NUL stated, given the above noted difficulties to reasonably forecast the start-up date and load of the Tamerlane mine, the company is proposing a deferral account be created to capture the material revenues and costs associated with providing service to Tamerlane. A deferral application would be filed with the Board by June 30 of the year following the interconnection of Tamerlane.

Hay River recommended that the proposed Tamerlane deferral account should also include indirect residential and commercial sales resulting from the potential Tamerlane Mine development. Hay River submitted if the mine enters the larger production phase in 2010 and the company does not file a GRA until 2011 or later, the lack of a retail sales deferral account may miss the impact of the 250-400 employees associated with the second phase of the project if it proceeds. Further, there is no evidence that the company has added any commercial load for ore handling or loading at the rail facilities at Hay River in the test period. The Town submitted there is everything to gain and nothing to lose by implementing a deferral account for indirect residential and commercial retail sales from the Tamerlane mine development,

NUL submitted its Hay River residential customer growth forecast of 1.8%, 1.3% and 1.3% in 2008, 2009 and 2010 respectively, as compared with an average annual growth rate of 0.9% over the past 10 years, reasonably incorporates the potential of indirect residential sales arising from the start up of the Tamerlane pilot project. NUL also cautioned that it would be virtually impossible to administer this type of item in practice as the company cannot track whether sales are attributable to the Tamerlane mine or some other reason.

Views of the Board

The Board notes NUL's submission that its customer forecast reasonably incorporates the potential of indirect residential sales arising from the start up of the Tamerlane pilot project.

The Board considers if customer additions over and above those reflected in the GRA forecasts were to occur due primarily to the start up of the Tamerlane project this could result in higher sales and revenues. However, there would also be the offsetting costs of adding facilities and services to connect these customers. Given these offsetting impacts, the Board considers it unlikely the company would see a windfall gain as a result of higher than forecast customer additions during the test period.

The Board notes the difficulties of setting up a deferral account that would capture only those changes in costs and revenues that are attributable to the start up of the Tamerlane project.

Having regard to the materiality of the potential revenues and costs resulting from residential and commercial customer growth incidental to the Tamerlane project, the Board is not persuaded that the deferral treatment proposed by the Town is needed. Accordingly, the Board does not accept the Town's recommendation.

The Tamerlane deferral account requested by NUL to capture the material revenues and costs associated with providing service to Tamerlane project is approved.

10. OTHER MATTERS

10.1 Taxes Other Than Income

The taxes other than income are the franchise fee and property taxes and are explained in Section 6 of the Application.

The franchise fee is paid to the Town of Hay River based upon the Franchise Agreement which grants NUL the exclusive rights to distribute electricity to the Town and its residents. The franchise fee, which is based on 4% of revenue generated in the Town, is forecast to be $210,000, $211,000 and $213,000 for the test years 2008, 2009 and 2010, respectively.

None of the other communities impose a franchise fee on NUL as they are not tax-based communities.

The property taxes are paid to the communities for NUL's office building, generation facilities, substation properties and power lines. The property taxes are forecast to be $39,000, $40,000 and $41,000 for the test years 2008, 2009 and 2010, respectively.

Hay River and Fort Providence had no comments in their arguments regarding taxes other than income.

Views of the Board

The Board has not identified any concerns with taxes other than income for the test years. The Board approves the taxes other than income for the test years as proposed by NUL.

10.2 International Financial Reporting Standards (IFRS)

With respect to the introduction of IFRS, NUL stated as follows:

> "On February 13, 2008, the Canadian Accounting Standards Board confirmed that IFRS will replace Canadian GAAP for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Comparative information based on IFRS to be included with the 2011 financial statements will have to be collected beginning in 2010. To date the ATCO Group of companies has completed the following in preparation for these deadlines: appointed a Steering Committee, assigned a Project Manager, developed an Implementation Working Group comprised of senior financial employees from each of the operating companies, hired an external consultant to assist with the conversion, identified the key differences between IFRS and Canadian GAAP, and provided IFRS training to key employees." (YK NUY 6a)

Fort Providence submitted the IFRS convergence project has the potential of having wide-ranging and potentially far-reaching cost impacts on customers. NUL should be directed to provide to the NWT Board and interveners the same information its parent ATCO Electric (either by itself or through the ATCO Group) will provide in response to the AUC's May 23, 2008 letter, identifying all impact(s) specific to NUL. A process should also be established for customers to provide feedback, as necessary, to the proposals advanced by NUL for it to be compliant with IFRS, particularly where such proposals involve accounting and regulatory changes which have a potentially significant impact on customer rates.

NUL submitted a formal process as has been established before the AUC should not be required as time and expense can be avoided by simply advising the Board of what is occurring regarding this matter. NUL stated, given the potential that a significant amount of resources may be required to address this issue, a process whereby NUL would provide updates to the Board (perhaps in the 25kV deferral account applications) should be sufficient to keep the Board and parties appraised of developments in this regard.

Views of the Board

The Board considers that a formal process as has been established before the AUC should not be required for NUL at this time. However, given the significance of the changes contemplated under IFRS, the Board considers it important that it be kept fully informed of any material changes in NUL's financial reporting as convergence towards IFRS proceeds. The Board directs NUL to provide such information to the Board and interveners on an as needed basis consistent with the Board's desire to be kept fully informed on developments respecting this matter.

10.3 Report of Finances and Operations

Fort Providence submitted, currently, company's annual reporting of its actual costs is limited to providing the Board with (i) a current list of directors and officers; (ii) rate schedules; and (iii) audited financial statements. Fort Providence submitted the information provided is of limited value in that it does not provide the Board and interveners any rationale to assess the nature and extent of changes in actual costs relative to the forecast approved costs. Any assessment of trending or other such analyses is therefore significantly limited by the lack of this information.

Fort Providence noted NUL's parent, AE, is required to file significantly more detail before the Alberta Utilities Commission ("**AUC**") of its prior year results. More specifically, the AUC requires utilities to provide information in accordance with its Rule 005, "Rules on Annual Reporting Requirements of Operations and Financial Reports". Fort Providence submitted one of the key objectives of this document is to provide the Commission with a thorough and reasonable understanding of the utility's operations.

NUL indicated it will file additional information similar to that currently filed with the Yukon Board.

Views of the Board

In the Board's view the annual filings should provide the Board with a thorough and reasonable understanding of the utility's operations. The Board expects NUL to file annual reports of finances and operations that are consistent with the spirit and intent of this objective.

10.4 Funds Accumulated for Meeting Pension and Other Post Employments Benefits

Fort Providence submitted that included in the company's no-cost capital for each of the Test Years 2008-2010 is $168,000 with respect to amounts previously collected from customers for pension and post employment benefits i.e. amounts collected from customers in respect of pension expense exceed the required funding amounts. Fort Providence submitted these funds should be refunded as there is no need for these funds either on an imminent basis, or even for the foreseeable future. NUL should be directed, in its Refiling, to propose a method of refunding the $168,000, appropriately grossed-up for income taxes, to customers.

Fort Providence submitted, since the company is on a cash basis for pension accounting, the amount of pension expense will equal the amount of required pension funding. To the extent a pension shortfall exists as in this GRA, NUL will apply for recovery of the additional pension funding required through an increase in customer rates. Hence, NUL's assertion that it needs to collect the pension "regulatory asset" before it can refund the $168,000 has no merit.

NUL submitted Fort Providence's proposal is inconsistent with attempting to achieve intergenerational equity and would improperly impose a burden on future customers. In NUL's view the amount of the regulatory asset currently recorded exceeds the fund amount of $168,000.

NUL submitted given the uncertainties surrounding the accounting treatment that will be permitted under IFRS, such action is premature. NUL submitted at the very least the matter should be deferred until the next GRA when this aspect of the issue should be clarified further.

Views of the Board

The Board notes Fort Providence's submission that since the company is on a cash basis for pension accounting, the amount of pension expense will equal the amount of required pension funding. To the extent a pension shortfall exists as in this GRA, NUL will apply for recovery of the additional pension funding required through an increase in customer rates. The Board agrees with Fort Providence under the present rules, namely the cash basis for pension, there is no need to hold in no cost capital the $168,000 previously collected from customers to fund pension and OPEB. NUL is, therefore, directed to propose a method of returning the $168,000 to customers in its refiling application either through a reduction in the pension expense or, by way of an outright refund.

10.5 Transmission Line Option to Diesel Communities

In Decision 9-2006, the Board directed NUL as follows:

> “Northland is directed to provide a preliminary assessment of feasible energy supply alternatives for diesel communities, including those referred to by the Hamlet, that may help alleviate the high cost of providing electricity supply to these communities, as part of its next resource planning cycle and provide Northland’s recommendations thereon to the Board and interested parties by year end 2006. Following this filing, the Board may direct that further detailed studies or a further process be undertaken or may conclude that the matter needs no further action.” (Decision 9-2006; p. 63)

NUL indicated, in 2006, the company initiated a study to conduct a preliminary assessment of the feasibility of constructing a 72 kV transmission line from Hay River to the communities of Fort Providence, Dory Point and Kakisa. Specifically, this study compared the total capital and O&M cost of operating the existing plants in these communities with the total capital and O&M cost of building the transmission line that would ultimately tie these communities into the interconnected system. This preliminary study was completed during the third quarter of 2007.

NUL stated the estimated cost of constructing the 122 km 72 kV line of $15.9 million was completed in the early part of 2007 and was based on the cost to construct a similar line in northwestern Alberta as opposed to a detailed field check and ground survey of a possible route. As construction costs in Alberta have increased dramatically since the time this estimate was prepared, it is likely that 2008 capital costs would be higher than the original estimate of $15.9 million.

NUL stated under ‘normal assumptions’, the required no cost capital contribution to make the Transmission line economical over a 20 year horizon would be approximately $8.7 million. Changing the forecast fuel expense by 30% and escalating it by 5% per annum thereafter still results in a required up front contribution of approximately $5.0 million. In order to come close to a break even situation over a 20 year horizon, capital costs would need to be approximately $11.1 million, or more than 30% lower than originally estimated $15.9 million. NUL stated it is expected that a detailed field check, engineering and construction estimate using 2008 prices would result in the cost capital cost exceeding the $15.9 million. This scenario would mean an increase to the above noted required no cost capital contribution of $8.7 million.

NUL stated the sheer magnitude of the no cost capital contribution suggests the need for a significant government and/or customer contribution to keep rate payers whole. Pending review and comment by the Board of the above findings, Northland has not pursued detailed engineering and or construction cost estimates.

NUL stated the company does intend to discuss the high level economics with the affected communities to determine if there may be ways and other funding options that may make the project more viable. In the event that the transmission line option which affects Fort Providence, Kakisa and Dory Point cannot be made feasible, Northland will review the potential option of a micro-hydro to serve the community of Kakisa and possibly Dory Point.

Fort Providence submitted, considering the significant increase in fuel prices in recent months, and the fact that the Deh Cho Bridge is slated to be completed in 2011 or 2012, Fort Providence concurs with NUL that other options to displace diesel-based generation be assessed in further detail only after the transmission line option is discounted. Fort Providence recommended NUL be directed as follows:

(i) To provide, by December 31, 2008, a comprehensive study in respect of the feasibility of the transmission line option.

(ii) To record all amounts incurred to study this project in a deferral account, and the company should provide evidence respecting the prudence of such amounts.

(iii) If this study suggests the line option is feasible, to immediately bring forward a project permit application rather than wait until the next GRA.

(iv) To provide detailed evidence of all efforts NUL has made to secure Federal/Territorial funding, quantify the reduction in greenhouse gas emissions and complete an assessment of potential “green credits” available from such a project.

NUL submitted it is prepared to move forward with the study of the transmission line option for diesel communities if so directed by the Board. NUL indicated significant costs will be incurred which are presently not included in the Application. Accordingly, NUL submitted that a deferral account should be established to recover the costs of the study, if it were to go ahead.

Views of the Board

During hearing examination NUL indicated it has not investigated the funding of a study with the Federal or Territorial Governments:

> " THE CHAIRPERSON: Okay. All right. I guess the next question would be, you mentioned about approaching the Federal government or the Territorial government about a capital contribution for the transmission line.
>
> But your first reaction for this cost of the study -- and I think you said two (2) to three hundred thousand dollars ($300,000) would go to the revenue requirement to get it from the ratepayers.
>
> And the recent GNWT budget that was passed, they have a rather significant amount of money set aside to try and increase the use of hydro in the Northwest Territories. And -- and a project to take communities from diesel to hydro, I think, would also qualify under some of the Federal government's greenhouse gas emission programs.
>
> So have you approached either the Federal or Territorial government about sharing or covering the cost of the transmission line study rather than going back to the ratepayers for that?
>
> MR. JEROME BABYN: We haven't at this point.
>
> THE CHAIRPERSON: Are you going to?
>
> MR. JEROME BABYN: I mean, certainly we - we could have the, you know, the discussion with government to see if there's any -- any dollars available to do something like that.
>
> You know, I guess we were looking at it from the point of view of -- of, again, adding to the power system in which customers all share in those costs, you know, new and existing customers. And so that was a context in which we were -- we were proceeding with the project.
>
> Having said that, I mean, we wouldn't be opposed, I guess, to, you know, bringing it forward to the -- to the government to see if there was, you know, availability of funding. I'm not sure what the response would be at this point." (Tr., p. 277, *l*. 3 – p. 278, *l*. 15)

The Board directs NUL to investigate the availability of funding for the transmission line study as well as for the project, with different levels of Government and report back to the Board by December 31, 2008. The information should also be provided to interested parties. As part of the December 31, 2008 report, NUL should also come forward with a proposal on whether to proceed with the study of the transmission line option or any other option as a viable alternative to diesel generation. The Board will make a determination on the matter following receipt of this information.

11. SUMMARY OF BOARD DIRECTIONS

Phase 1 Refiling

1. The Board directs NUL to reflect the 2007 actual plant closing balances in the plant opening balances for 2008 in its Phase 1 refiling.

2. The Board determines a common equity ratio of 44% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

3. In light of the Board's determination on capital structure, the Board considers NUL may need to raise new debt within the test period. The Board considers that it would be appropriate for NUL to include any new debt at the cost rate for new debt approved for NUY in Decision 24-2008. NUL is accordingly directed to reflect this determination in its Phase I refiling application.

4. The Board directs that, in its Phase 1 refiling, NUL is to apply a 12% combined loss and station service cap as a percentage of generation.

5. The Board directs that, in its Phase 1 refiling, NUL is to use the following inflation amounts for employees:

   - In-scope 11% in 2008, 5.25% in 2009 and 5.25% in 2010
   - Out-of-Scope 10% in 2008, 5.25% in 2009 and 5.25% in 2010

6. The Board directs that, in its Phase 1 refiling, NUL is to apply an inflation rate of 3.2% to operating materials and supplies plus the non-affiliate and non-contractor costs.

7. The Board directs NUL to limit the increase in the Oracle Financial expense to 3.2% for 2010 and reflect this finding in the refiling application.

8. NUL is directed to escalate the base billing charge using an inflation rate of 5% over the 5 year period so that the average of the rate over that period amounts to $1.72 and, to reflect this change in the refiling of the application.

9. The Board directs that, in its Phase 1 refiling, NUL is to use a forecast cost for the current Phase 1 and 2 GRA that is the greater of the following 2 options:

    1) the $433,000 cost of the previous GRA; or
    2) an updated forecast cost of the current Phase 1 and 2 GRA with rates for NUL's legal counsel capped at $350/hr and the cost of capital expert capped at $270/hour.

    If NUL proceeds with Option 2, then it will be expected to provide supporting evidence and calculations.

10. NUL is directed to adjust its residential sales forecast for the test period to reflect the three year average normalized UPC from 2005 to 2007, for all communities, for purposes of the refiling application. For the community of Dory Point, because of the extremely low correlation between UPC and temperature, NUL is directed to use the 3-year average UPC including 2007 for purposes of the refiling application.

11. For the purposes of determining the commercial sales forecast for all communities NUL is directed to use the three year average commercial UPC including 2007. To be consistent, NUL is also directed to use the 3-year average lighting usage per type of light including 2007, for the purposes of determining the lighting sales forecast for all communities. NUL should reflect these directions in its refiling Application.

12. The Board agrees with Fort Providence under the present rules, namely the cash basis for pension, there is no need to hold in no cost capital the $168,000 previously collected from customers to fund pension and OPEB. NUL is, therefore, directed to propose a method of returning the $168,000 to customers in its refiling application either through a reduction in the pension expense or, by way of an outright refund.

Next Phase 1 GRA

13. The Board directs that, in its next Phase 1 GRA, NUL is to compare the overall fuel efficiency of each plant to the manufacturer's rated engine efficiency for each engine within that plant. If there are significant discrepancies between the overall plant efficiency and the individual rated engine efficiencies, NUL is to provide an explanation and potential solutions to improve plant efficiency.

14. The Board directs that, in its next Phase 1 GRA, NUL is to calculate forecast fuel efficiencies using three years of data weighted 3 for the highest efficiency year, 2 for the middle efficiency year and 1 for the lowest efficiency year.

15. The Board directs that, in its next Phase 1 GRA, NUL is to give due weight to earlier test year forecast fuel efficiencies when calculating the later test year forecast fuel efficiencies.

16. The Board directs that, in its next Phase 1 GRA, NUL is to provide separate analysis and discussions for losses and station service.

17. The Board directs that, in the next Phase 1 GRA, NUL is to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.

18. The Board directs that, in the next Phase 1 GRA, NUL is to calculate station service using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” given to the middle station service year and a weighting of “1” given to the highest station service year.

19. Consistent with its directions respecting fuel efficiencies, the Board directs that, in its next Phase 1 GRA, NUL is to give due weight to earlier test year station service forecasts when calculating the later test year station service forecasts.

Other Directions

20. The Board directs that, within 90 days of the conclusion of the Phase 1 and Phase 2 GRAs, NUL will file a cost claim with the Board covering both Phase 1 and 2.

21. The Board directs NUL to include all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the income tax deferral account.

22. The Board considers that a formal process as has been established before the AUC should not be required for NUL at this time. However, given the significance of the changes contemplated under IFRS, the Board considers it important that it be kept fully informed of any material changes in NUL's financial reporting as convergence towards IFRS proceeds. The Board directs NUL to provide such information to the Board and interveners on an as needed basis consistent with the Board's desire to be kept fully informed on developments respecting this matter.

23. The Board directs NUL to investigate the availability of funding for the transmission line study as well as for the project, with different levels of Government and report back to the Board by December 31, 2008. The information should also be provided to interested parties. As part of the December 31, 2008 report, NUL should also come forward with a proposal on whether to proceed with the study of the transmission line option or any other option as a viable alternative to diesel generation. The Board will make a determination on the matter following receipt of this information.

12. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NUL to provide to the Board and interested parties a Phase 1 refiling reflecting the findings and directions in this Decision within 30 days of the release of the Board's Phase 2 Decision.

2. The Board directs NUL to provide as part of the Phase 1 refiling a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.

3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northland Utilities (NWT) Limited.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

Joe Acorn
Chairman

Dated October 27, 2008

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 24-2008 **October 27, 2008**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (Yellowknife) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (Yellowknife) Limited to their customers within the Northwest Territories, by seeking approval of the Phase 1 General Rate Application.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Joe Acorn	Chairman
	John Hill	Vice-Chairman
	William Koe	Member
	Sandra Jaque	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Loyola Keough	Counsel for Northland Utilities (Yellowknife) Limited
Thomas Marriott	Counsel for the City of Yellowknife
Doug Ritchie	Program Director, Ecology North

WITNESSES

Northland Utilities (Yellowknife) Limited

Jerome Babyn	General Manager
Jeff Barbutza	Manager
James Grattan	Manager, Pricing
David Freedman	Director, Regulatory
Kathy McShane	Consultant for Northland

City of Yellowknife

Robert Bruggeman	Consultant for the City of Yellowknife
Azad Merani	Consultant for the City of Yellowknife
William Marcus	Consultant for the City of Yellowknife

ABBREVIATIONS

Act	*Public Utilities Act*
AMR	Automatic Meter Reading
AUC	Alberta Utilities Commission
Board	Northwest Territories Public Utilities Board
BR	Board Information Request
CC&B	Customer Care and Billing
CEO	Chief Executive Officer
City	City of Yellowknife
COLA	Cost of Living Adjustment
CRA	Canada Revenue Agency
CPI	Consumer Price Index
CPV	Cumulative Present Value
CU	Canadian Utilities
DB	Defined Benefit
DC	Defined Contribution
EN	Ecology North
Ex	Exhibit
FFO	Funds from Operations
FMV	Fair Market Value
FTE	Full-Time Equivalent
GAAP	Generally Accepted Accounting Principles
GRA	General Rate Application
Hay River	Town of Hay River
IFRS	International Financial Reporting Standards
IT	Information Technology Services
ITBS	Information Technology Billing Services
I-Tek	ATCO I-Tek
kV	Kilovolt
kWh	Kilowatt-Hour
l.	Line
Northland	Northland Utilities (Yellowknife) Limited
NTPC	Northwest Territories Power Corporation
NUL	Northland Utilities (Yellowknife) Limited
NWT	Northwest Territories
O&M	Operation & Maintenance
p.	Page

R.S.N.W.T.	Revised Statutes of the Northwest Territories
Test Years	2008/2010 test period
TWACS	Two-Way Automatic Communication System
UPC	Usage per Customer
Yellowknife	City of Yellowknife
Yk	Yellowknife Information Request

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1. BACKGROUND & APPLICATION

By letter dated February 8, 2008, Northland Utilities (Yellowknife) Limited (“**Northland**”, “**NUL**”) submitted to the Northwest Territories Public Utilities Board (“**the Board**”) a General Rate Application (“**GRA**”, “**Application**”) for the 2008/2010 test period (“**Test Years**”) (Ex. 2).

In its Application, Northland requested order or orders of the Board to:

a) Determine the Company’s rate base and revenue requirement for the forecast test years 2008, 2009 and 2010;
b) Continue utilizing 4 deferral accounts – Purchased Power Flow Through Deferral Account, Capital Deferral Account, Defined Benefit and Contribution Pension Plan Cash Contribution Deferral Account and Income Tax Rate Variance Deferral Account

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated February 15, 2008 directed Northland to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notice provided details of the GRA and invited interested persons to file a request with the Board for intervener status (Ex. 1).

The City of Yellowknife (“**the City**” or “**Yellowknife**”) registered their respective interventions with the Board, by letter dated February 22, 2008. Ecology North of Yellowknife **(“EN”, “Ecology North”)** indicated an interest in the proceeding, by a fax dated April 9, 2008. The Northwest Territories Power Corporation (**“NTPC”**) also indicated an interest in the proceeding.

The Board, the City and NTPC submitted information requests, to which Northland responded on April 7, 2008 (Ex 3).

The Board and Northland submitted information requests to the City in regards to its intervener evidence (Ex. 4). The City responded to the information requests on May 20, 2008 (Ex. 5).

Due to the delay in advertising Northland's GRA, the Board decided to allow EN to file their information requests by April 21, 2008, to which Northland responded on April 28, 2008 (Ex. 3). Ecology North, by letter dated May 12, 2008, submitted intervener evidence (Ex. 6). The Board and the intervener did not submit any information requests to EN's evidence.

2. PUBLIC HEARING

Public Notice of the hearing was published in the *Yellowknifer* on April 2, 2008 and June 4, 2008 and in the *News/North* on April 7, 2008 and June 2, 2008 (Ex 1). The hearing was held in the City of Yellowknife on June 18 and 19, 2008 and in the Town of Hay River on June 25, 2008.

The hearing was adjourned in Yellowknife on June 19, 2008 and reopened in Hay River on June 25, 2008 to hear the City's witness, Mr. Azad Merani and to set the dates for argument and reply argument.

During the course of the hearing, members of the public who had not initially requested intervener status were invited to participate in the proceeding but there were no additional interveners identified.

The Board and all interested parties agreed to set July 14, 2008 for the written argument and July 28, 2008 for the written reply argument.

3. RATE BASE

The determination of the rate base, for the purpose of fixing just and reasonable rates, is governed by the provisions of Section 49 of *the Public Utilities Act (“**the Act**”)*, which states:

> “49 (1) In fixing just and reasonable rates, the Board shall determine a rate base for the property of the public utility used or required to be used to provide service to the public within the Territories.
> (2) In determining a rate base, the Board shall consider
> (a) the cost of the property referred to in subsection (1) at the time that property was first devoted to public use, and to the prudent acquisition cost to the public utility, less depreciation, amortization or depletion; and
> (b) the necessary working capital of the public utility.”

This section of the Decision examines the issues raised with respect to determination of NUL’s rate base for the test years.

3.1 2007 Opening Balances

The Board considers the best available information at the time of the hearing should be reflected in the test year forecasts. Accordingly, the Board directs NUL to reflect the 2007 actual plant closing balances in the plant opening balances for 2008 in its Phase 1 refiling.

3.2 Capital Additions

Capital additions were detailed in Section 8 of the Application and are forecast to be $4.103 million, $6.161 million and $7.357 million for the test years 2008, 2009 and 2010, respectively. This section of the Decision examines the issues raised with respect to capital additions to the rate base.

3.2.1 Customer Care and Billing System

NUL proposed to begin converting to a new billing system in 2007 with the project completed in 2008. NUL forecast costs of $236,000 in 2007 and $513,000 in 2008. While the old billing system continued to met NUL's basic needs, it was determined that the existing system would no longer be cost-effective due to the larger ATCO Alberta utilities migrating away from the existing system to a new ATCO system. ATCO's northern affiliated such as NUL would have been left to bear the full operating and maintenance cost of the old system.

Yellowknife was concerned about a lack of transparency by NUL in its decision to select and implement the new ATCO billing system over two competing products. However after reviewing additional information provided by NUL in its rebuttal evidence and examining NUL at the hearing, Yellowknife stated in its argument that it does not oppose the implementation of the new billing system and its inclusion in the rate base.

Views of the Board

The Board is satisfied that this matter was thoroughly examined and approves the addition of the new billing system to the rate base.

3.2.2 Automatic Meter Reading (AMR) Implementation and Conversion of Residential Mechanical Meters to Electronic Meters

NUL proposed that in 2010 it would convert its manual meter reading system to an Automatic Meter Reading ("**AMR**") system known as TWACS (Two-Way Automatic Communication System). NUL asserted that the project would improve customer service as well as provide long-term savings for customers and reduced environmental impact. NUL also noted that the project would move NUL's metering technology towards being able to process time-of-use rates. he projected cost of this project is $2.558 million in 2010.

For an additional cost of $0.483 million in 2010, NUL was also proposing to replace about 700 residential mechanical meters with electronic meters. While the meter conversion is necessary for the AMR project, NUL stated that the meter conversion project is economically justified on its own.

Yellowknife expressed concern about the Cumulative Present Value ("**CPV**") of the AMR project was only $0.165 million and that the economic cross-over did not occur for 20 years.

In rebuttal, NUL made corrections to its initial economic analysis and also provided some new information. NUL acknowledged that 1) the mechanical meters must be replaced with electronic meters for the AMR to function; and 2) there were no line loss savings associated with electronic meters per se although there were other benefits. For these reasons, Yellowknife asserted in its argument that the only meaningful CPV analysis is one that combines the capital and operating costs associated with both AMR and the conversion from mechanical to electronic meters.

At the hearing, NUL was requested by Yellowknife to provided additional CPV evaluations: 1) break-even; 2) 10% cost overrun; and 3) 20% cost overrun. As a result of these evaluations, Yellowknife remained concerned that the economics of this project were slim and that the potential exists for cost overruns to make the combined AMR/meter conversion project uneconomic. Yellowknife recommended that the Board should approve the combined AMR/meter conversion project subject to capital expenditure cap of $3.4 million to ensure that customers are no worse off after this project.

In its reply, NUL argues that the cost estimates it has provided are based on the best available information available to the company and that those estimates demonstrate that there will be a cost savings for the customer. With regards to a capital cost cap, NUL stated that it assumes the risk that it will have to justify any cost overruns so a capital cost cap is not required.

Views of the Board

The Board agrees with Yellowknife that the strong linkage between these two projects requires evaluating them in tandem rather than as separate stand-alone projects and so the Board has combined the two projects into this section of the decision.

The Board also agrees with Yellowknife that on the basis of a strict economic evaluation, the combined AMR/meter conversion project appears to produce benefits to the customers that could be eliminated by cost overruns that would not need to be that significant.

However, that Board is also of the view that the implementation of new and improved technology does not need to be completely justified by a strict economic evaluation. The potential for future benefits, economic or otherwise and even if not yet fully identified and quantified, needs to be considered by the Board. As stated by NUL, additional functionalities such as remote disconnect capability, time-of-use metering and smart metering are add-ons to the basic AMR/meter conversion project that could produce future benefits but which have not been included in the current economic evaluation.

The Board agrees with NUL that it bears the risk of justifying any project cost overruns and any associated disallowance of costs by the Board. As a result, the Board does not see the need for a capital cost expenditure cap as recommended by Yellowknife.

The Board approves the AMR/meter conversion project as proposed by NUL for addition to the rate base in 2010.

3.3 Capital Deferral Account

NUL is proposing a Capital Deferral Account through to 2012 specifically for the 25 kV conversion project. In Section 7, NUL states:

> As noted in the testimony, the cost of capital evidence has been prepared based upon the assumption that the Board accepts Northland's continued request for a deferral account for capital additions relating to the 25 kV conversion. If the Board were to deny the continued use of this deferral account, the business risks faced by Northland would be significantly enhanced and would result in a significant increase in the fair rate of return, the common equity ratio or both.
>
> (GRA, Section 7, p. 7-2)

Yellowknife did not submit any comments regarding the Capital Deferral Account.

Views of the Board

The Board approves use of the Capital Deferral Account as proposed by NUL.

3.4 Working Capital

NUL's calculation of necessary working capital for the test years is set out in Schedules 7.5 and 7.9 of the Application. To determine the working capital for the test years, a study was undertaken to determine the revenue lead lag days. This study was provided as Attachment 2 to Section 7 of the Application.

Yellowknife did not raise any concerns with regards to working capital in its argument.

Views of the Board

The Board has not identified any concerns with the amount of working capital for the test years. The Board approves the working capital amounts for the test years as proposed by NUL.

4. RETURN ON RATE BASE

Having determined the rate base for NUL for the test years, the Board is required, pursuant to section 50 of *the Act*, to fix a fair return on the rate base.

Section 50 of *the Act* provides as follows:

> "50. (1) The Board shall fix a fair return on the rate base of a public utility.
> (2) In fixing a fair return, the Board shall consider all the facts that it considers relevant."

The Board's objective in fixing a fair return on rate base is to enable NUL to recover its cost of servicing those portions of the rate base financed by long and short term debt and to provide an opportunity to earn a fair return on the portion of rate base deemed to be financed by common equity.

4.1 Capital Structure and Return on Equity

NUL proposed a capital structure containing a common equity ratio of 47.5% in conjunction with an allowed return of on equity of 9.6% for the test period.

Ms. McShane, expert witness for NUL, concluded NUL was of higher than average business risk relative to the typical Canadian Utility. She indicated NUL's higher than average business risk relates to the very small size of the utility and the fact that it operates in a service territory with an undiversified economic base tied to a single industry and it faces significant physical/operating challenges. Ms. McShane noted that since NUL's debt is raised by Canadian Utilities Inc. ("**CU**"), NUL should contribute its fair share toward the maintenance of CU Inc's debt rating. Ms. McShane indicated the common equity ratio that would fully compensate for NUL's higher business risk lies at the upper end of a range of 47.5% to 52.5%. Ms. McShane arrived at her recommendations having regard to data from other electric utilities, rating agency guidelines and rating agency commentary.

Ms. McShane did not recommend a move to the 52.5% equity ratio. She expressed two concerns with moving the common equity ratio to 52.5%. First, in her view, the shareholders considered the benchmark rate of return to be too low; therefore she questioned why they would want to invest additional equity in order to have the opportunity to earn an inadequate return. Second, in Ms. McShane's view, requiring minority shareholders to make an equity infusion would create an additional level of risk to those shareholders. Accordingly Ms. McShane recommended the benchmark rate of return on equity of 9.1% should be increased by 50 basis points to 9.60% rather than increasing the common equity ratio.

Mr. Marcus, expert witness for Yellowknife, recommended an equity ratio of 40 to 42% for NUL's operations – a figure that is, in Mr. Marcus' view, modestly but not inordinately higher than the benchmarks for large utilities in Canada, that is consistent with the Ontario Energy Board's determination for small electric distribution companies and consistent with the Alberta determination for AltaGas, also a small gas utility. Mr. Marcus submitted the Board should reject the increased return on equity recommended by Ms. McShane in lieu of a further increase in the equity percentage.

With respect to the separate systems operated by Northland, one being Northland Utilities (Yellowknife) Limited and the other being Northland Utilities (NWT) Limited, Mr. Marcus stated the Board should not be paying Northland Utilities Limited more money just because it operates similar types of utilities in two different towns and raise the equity percentage further by considering that each individual utility is smaller than the entire Northland Utilities Limited system. Mr. Marcus stated it is unreasonable to balkanize the system in this way. Mr. Marcus did not see any reason why Northland Utilities Limited should be different than NTPC which is treated as a unified system.

With respect to business risk, Yellowknife submitted NUL is basically a distribution utility and provides none of its own generation. It purchases its power from the NTPC and has full deferral account protection on both the amount and cost of purchased power. The City submitted NUL faces less regulatory risk than a company owning considerable amounts of generation. The complexity of generation projects results in the potential for prudence reviews by regulators as well as temporary disallowances or phase-ins because of excess capacity. The City stated the Yellowknife system has less weather-related demand risk than a gas distribution company but somewhat more demand forecasting risk than a typical electric utility “due to its location in a limited area with dynamic economic conditions that can change relatively quickly.” The City submitted, despite the cold climate, Northland did not experience unusual weather-related risks when compared to utilities facing events such as ice storms, hurricanes, tornadoes, and earthquakes.

The City stated NUL’s cost control and cost forecasting risks appear to be similar to other Canadian distribution utilities with future test year ratemaking (which places Northland in a less risky position relative to those US utilities using historical test year ratemaking). The City submitted NUL’s distribution capital deferral account reduces risk slightly relative to both other Canadian utilities and Northland Utilities (NWT) Limited.

NUL submitted looking only at the equity ratios adopted by regulators renders Mr. Marcus' analysis completely circular. Moreover, Mr. Marcus' analysis failed to take into consideration the following:

- The quantitative impact on capital structure of the additional fifty basis points in return on equity that the Board allowed NTPC
- Other relevant allowed capital structure benchmarks such as that of Newfoundland Power
- Any bond rating or interest coverage analysis
- Debt rating agency guidelines for capital structure
- The actual capital structure maintained by Canadian utilities
- Any relevant changes in income tax rates, allowed returns on equity or capital cost allowance rates since the 2004 Alberta Decision that have negatively impacted interest coverage ratios for the Alberta utilities used as benchmarks in his analysis

Views of the Board

The Board notes both NUL and the City agree that NUL's business risks are somewhat higher than those applicable to an average electric utility primarily due to its small size and economic characteristics of the service area. However, they differ in their assessment of the extent to which the various risk factors contribute to NUL's overall business risk. Mr. Marcus, for the City, summarized the key differences between Ms. McShane's and his assessment of NUL's business risks as follows:

> "Ms. McShane identifies the same risks as listed above. She specifically states that demand risks are the greatest, followed by regulatory risks and then by physical and supply risks.

> Among the demand risks, she places more emphasis on the pure size of the utility than does Mr. Marcus. She also places more emphasis on alleged potentially detrimental effects of the Government's energy conservation policies, while Mr. Marcus believes that energy conservation policies have only a small short-term forecasting impact on NUL. Both Ms. McShane and Mr. Marcus place emphasis on the volatility in growth rates and the composition of the service area.
>
> Ms. McShane places considerably more emphasis on the physical system risk of NUL – that it is served by a single transmission line and is therefore more subject to outages and is subject to severe weather conditions. We place less emphasis on this factor because costs associated with weather risks appear to be modest as compared to other utilities that face ice storms, hurricanes, etc., while the risks associated with transmission are largely NTPC risks to get the power to Yellowknife. Mr. Marcus recognizes a cost containment risk is related to the physical system – that the utility's ability to earn authorized returns is related to its ability to meet its forecast costs.
>
> Ms. McShane believes that regulatory risk is higher than does Mr. Marcus for a utility engaged in power distribution; Mr. Marcus believes that such risk tends to be considerably lower for utilities who do not own significant amounts of generation. Mr. Marcus and Ms. McShane agree that the risk in Yellowknife is mitigated by the deferral account for the rebuilding of the distribution system but disagree regarding the magnitude of the remaining risk.
>
> Ms. McShane believes that franchise risk is important and could significantly harm shareholders if the system were to be municipalized. Mr. Marcus does not believe that shareholder harm would be material given existing rate of return regulation of the utility – the shareholders would receive at least a return of capital for reinvestment if not a higher amount for the difference between original cost less depreciation and replacement cost new less depreciation." (BR YK 1a)

The Board agrees NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area. On the other hand NUL does not own generation assets, which suggests, lower regulatory risks compared with an integrated utility. Further NUL's purchased power costs and certain significant capital additions are subject to deferral account treatment. In the Board's view these factors would tend to have an offsetting effect on the increased risk resulting from small size and economic characteristics of the service area.

In terms of peer comparisons, the Board notes the 41% equity ratio awarded by the Alberta Energy Utilities Board to AltaGas, a gas utility that is of relatively small size although larger than NUL in terms of size. The Board also notes Newfoundland Power was awarded an equity ratio of 44.5% together with an equity risk premium of 0.15%. (Table 5 McShane Testimony) Maritime Electric was awarded 42.7% with an equity premium of 1.25% higher than the average Canadian utility. (Table 5 McShane Testimony) The Board notes although both Newfoundland Power and Maritime Electric are larger utilities they also own generation assets. In reviewing peer comparisons the Board is also cognizant of the impact of changes in tax and capital cost allowance rates on coverage ratios.

The Board notes the following coverage ratios for NUL for the years 2006 Actual and 2007 Forecast and for the forecast test years 2008 to 2010 under the proposed capital structure and proposed return on equity:

Table 1 NUY Proposed Coverage Ratios
($000s)

	2006A	2007	2008	2009	2010
Total Return	1,828	1841	2292	2579	2947
Income Tax	326	272	182	408	433
EBIT	2,154	2,113	2,474	2,987	3,380
Depreciation net of Amortization of Contributions	1,215	1,302	1,582	1,787	2,047
Funds from Operations	3,369	3,415	4,056	4,774	5,427
Debt Interest	838	920	981	1079	1225
Interest Coverage	2.57	2.30	2.52	2.77	2.76
FFO Interest Coverage	4.0	3.7	4.1	4.4	4.4

Note: Table 1 reflects original filing

The Board notes from Table 1 NUL achieved interest coverage ratio of 2.57 and a funds from operations ("**FFO**") interest coverage of 4.0 in 2006. The 2005 and 2006 test years were the subject of a negotiated settlement. The Board recognizes that coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.

Having weighed all of the evidence, the Board considers that an equity ratio of 43.5% together with the benchmark return on equity of 9.1% would result in a fair return on rate base for NUL in 2008, 2009 and 2010 that is consistent with the company's investment risks. The resulting approximate coverage ratios are set out below:

Table 2- NUY Return on Rate Base
($000s)

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 Test Period				
Long-term debt	54.40%	16670	5.79%	966
Common stock	43.50%	13329	9.10%	1,213
Customer Deposits	1.07%	328	4.59%	15
No Cost Capital	1.03%	316	0.00%	0
Total	100.00%	30,643	7.16%	2,194
2009 Test Period				
Long-term debt	54.66%	18501	5.79%	1,071
Common stock	43.50%	14724	9.10%	1,340
Customer Deposits	0.95%	322	4.59%	15
No Cost Capital	0.89%	301	0.00%	0
Total	100.00%	33,848	7.17%	2,426
2010 Test Period				
Long-term debt	54.84%	20986	5.82%	1,221
Common stock	43.50%	16646	9.10%	1,515
Customer Deposits	0.87%	333	4.59%	15
No Cost Capital	0.79%	302	0.00%	0
Total	100.00%	38,268	7.19%	2,751

Table 3 Coverage Ratios Based on Board Approved Equity Ratio and ROE
($000s)

	2006A	2007	2008	2009	2010
Total Return	1,828	1841	2,194	2,426	2,751
Income Tax	326	272	141	341	346
EBIT	2,154	2,113	2,335	2,767	3,097
Depreciation net of Amortization of Contributions	1,215	1,302	1,582	1,787	2,047
Funds from Operations	3,369	3,415	3,917	4,554	5,144
Debt Interest	838	920	981	1,086	1,236
Interest Coverage	2.57	2.30	2.38	2.55	2.51
FFO Interest Coverage	4.0	3.7	4.0	4.2	4.2

Notes:
1. Based on original filing
2. The embedded cost of debt in Table 2 has been adjusted to reflect the Board approved cost of new debt

The Board notes the coverage ratios resulting from a 43.5% common equity ratio together with a 9.1% return on equity will not be out of line with those achieved by NUL in 2006. The Board notes the FFO interest coverage ratios in 2008, 2009 and 2010 of 4.0, 4.2 and 4.2 would be higher than those applicable to the average Canadian utility of about 3.8 times. (McShane Testimony, p. 29, *l*. 762)

Accordingly, the Board determines a common equity ratio of 43.5% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. The Board notes the 9.1% equity return reflects a 5% long Canada bond rate. However, the Board has not adjusted the rate of return on equity to reflect lower forecasts of the long Canada bond rate in 2008 and 2009 determined in Section 4.2, having regard to the volatility in the credit markets. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

4.2 Cost of Debt

NUL forecast new debt issues of $2.45 million in 2008, $2.20 million in 2009 and $1.7 million in 2010. For each of these issues NUL forecast coupon rates of 7% and effective costs rates of 7.05%. NUL's forecasts were based on a long Canada bond yield of 5% plus 200 basis point spread difference for CU's corporate bonds plus 5 basis point issue costs.

Yellowknife, through the evidence of Mr. Bruggeman, recommended NUL's forecast cost of new debt should be updated to reflect the best and most recent information available to assess the debenture rate for new issues in the test years. Yellowknife submitted at the time the evidence was prepared in April 2008, the long Canada bond yield was 4.05% and there was no evidence on the record to suggest that amount would increases over the test period. The 10/30 long Canada spread was also 37 basis points at that time. Yellowknife submitted, by the end of March 2008, the corporate yield spread had increased to 149 basis points which is well above the spreads since November 2006. That information suggested a corporate debenture of 5.90% for CU Inc. Yellowknife noted that NUL did not provide any further information or updates in Rebuttal.

Yellowknife submitted further updates were canvassed at the hearing on June 19, 2008. Ms. McShane confirmed that the Consensus Forecast for Long Canada's was 3.6% for July 2008, 3.9% for April 2009 and 5.0% for 2010 based on the April 2008 Consensus Economics Report.

Yellowknife submitted based on the updated forecasts for long Canada's plus the 37 basis points for the 10/30 long Canada spread plus the 149 basis points for corporate yield spreads results in debenture rates of 5.46%, 5.76% and 6.86% for the test years or an average of 6.03%. Yellowknife submitted that the Board should either approve those respective amounts or alternatively a rate of 6.0% for all three test years.

NUL submitted in Reply argument that it takes issue with the approach adopted by Yellowknife. NUL submitted if the materials contained in the Application are updated for more recent forecasts, then the rates would be as follows:

	2008	**2009**	**2010**
Updated Consensus for Long Canadas	3.600%	3.900%	5.000%
Spread 10 versus 30 year	0.370%	0.370%	0.370%
Corporate spread	2.000%	2.000%	2.000%
Totals	5.970%	6.270%	7.370%

Northland noted that no evidence has been presented to suggest that a 200 basis point spread for corporate debt is not reasonable.

Views of the Board

The Board notes the corporate yield spread was 149 basis points in March 2008. The Board also notes NUL's view that the Corporate spreads would be in the 200 basis points range over the test period in view of the volatility in the credit markets. For purposes of this Decision, the Board accepts the 149 basis points corporate yield spread for purposes of determining the cost of new debt for the 2008 test year based on the most recent spreads alluded to by Yellowknife. Having regard to the volatility in the credit markets and the inherent risks of longer term forecasts, the Board accepts a spread of 200 basis points for the 2009 test year. Accordingly, the Board has determined the cost of new debt to be as follows for the 2008 and 2009 test years:

	2008	**2009**
Updated Consensus for Long Canadas	3.600%	3.900%
Spread 10 versus 30 year	0.370%	0.370%
Corporate spread	1.490%	2.000%
Issue costs	0.050%	0.050%
Totals	5.510%	6.320%

For the 2010 test year, the Board accepts the cost rate for new debt requested by NUL of 7.05% based on a long Canada bond yield of 5% plus 200 basis point spread difference for CU's corporate bonds plus 5 basis point issue costs having regard to the volatility in the credit markets and the inherent risks of longer term forecasts.

The Board directs that, in its Phase 1 refiling, NUL is to incorporate debt rates of 5.51% for 2008, 6.32% for 2009 and 7.05% for 2010 into its cost of debt calculation.

5. PURCHASED POWER AND ENERGY LOSSES

5.1 Purchased Power

NUL purchases all of its power requirements from the NTPC. The purchased power costs are outlined in Section 3 of the Application and total $24.704 million, $24.632 million and $24.756 million for each of the test years 2008, 2009 and 2010, respectively.

Yellowknife had no comments in its argument regarding purchased power expense.

Views of the Board

The Board has not identified any concerns with the purchased power expense for the test years. The Board approves the purchased power expense for the test years as proposed by NUL.

5.2 Purchased Power Flow Through Deferral Account

The costs of purchased power included in the Application are based on the NTPC's December 31, 2007 rates. NUL proposes that subsequent increases or decreases to those rates will be flowed through to NUL's customers using riders for the Purchase Power Flow Through Deferral Account and only as approved by the Board.

Yellowknife had no comments in its argument on the purchase power flow through deferral account.

Views of the Board

The Board has not identified any concerns with the proposed purchased power flow through deferral account. The Board approves the use of the deferral account as proposed by NUL.

5.3 Energy Losses

The total forecast purchase power expense was determined by applying an estimated line loss percentage to Northland's to NUL's sales load forecast (discussed in Section 2 of the Application). In accordance with Board Direction No. 2 in Decision 12-2005, forecast line losses were determined based on an engineering assessment of the level of line losses adjusted for the forecast impact of the 25 kV conversion. The engineering assessment was included as Attachment 1 to Section 3 of the Application.

Yellowknife had no comments in its argument regarding energy losses.

Views of the Board

The engineering assessment provided by NUL fulfills the requirement of Board Direction No. 2 in Decision 12-2005. The Board approves the use of the energy loss percentages of 5.0%, 4.9% and 4.9% proposed by NUL for the 2008, 2009 and 2010 test years, respectively.

However as noted by NUL in the engineering assessment, the total energy loss includes two types of losses: technical losses and non-technical losses. Non-technical losses are caused by a number of factors including accounting methods, metering errors and unmetered energy consumption. NUL states that the non-technical losses cannot be removed from the system loss calculation without incurring the considerable expense associated with an improved metering strategy and/or complex load modeling.

The Board notes that by the end of 2010 NUL intends to have completed the AMR/meter conversion project. Assuming that this upgrade in the metering system would enable the separation of non-technical losses from the system loss calculation, the Board directs that, in the next Phase 1 GRA, NUL is to include an examination of the pros and cons of separating losses into its two components (technical losses and non-technical losses) and, if determined desirable to do so, to calculate and include these two components in its calculations for the next GRA.

6. OPERATION AND MAINTENANCE EXPENSES

Operations and maintenance ("**O&M**") expenses were dealt with in Section 4 of NUL's application. NUL is seeking Board approval for O&M expenses of $2.943 million in 2008, $3.134 million in 2009 and $3.255 million in 2010.

Yellowknife raised various issues with respect to various aspects of O&M and these issues are discussed in the remainder of this section.

6.1 Inflation

6.1.1 Labour Inflation

NUL is forecasting labour inflation according to the following table.

	2008	**2009**	**2010**
Collective Agreement In-Scope	11%	5.25%	6%
Out-of-Scope	10%	6%	7%

The first two years for the in-scope employees is based on the collective agreement that was negotiated in 2007. The in-scope employees received an 11% increase in 2008 and a 5.25% increase in 2009. The higher increase in 2008 was due to an extra market adjustment that year. The 6% forecast for 2010 is based on expectations for a tight labour market.

Although not explained well by NUL, the out-of-scope increases for 2008 and 2009 appear to be based on amounts contained within the negotiated collective agreement. As for the in-scope employees, the 2010 increase for the out-of-scope employees is also based on the assertion of a continued tight labour market.

Yellowknife dealt with this matter in its argument.

> The City is prepared to accept the proposed wage increases for the in-scope group for 2008 and 2009 based on the collective agreement that was negotiated with those employees. However, there is no evidence on the record to support the 6% increase proposed for 2010 other than the anecdotal statement "to reflect an expected continued tight labor market." Each of the groups making up the in-scope employees received 5.25% plus market adjustments in 2008 to bring wages into line with ATCO Electric. There is no evidence to suggest that the labor market will be even tighter in 2010 than it was in 2008 and further that the Consumer Price Index is forecast to remain relatively flat through 2012. Therefore, in-scope increases should be limited to no more than 5.25% in 2010.
>
> With respect to out-of-scope increases, the City is prepared to accept that the 10% increase in 2008 brought this group up to market. However, there is no evidence to suggest that this group should be given an additional 1% over and above the in-scope group, notwithstanding the additional management responsibilities suggested by NUL during cross examination.
>
> **The City submits that salary and wage increases should be limited to the following for purposes of this application:**

	2008	2009	2010
Collective Agreement In-Scope	**11%**	**5.25%**	**5.25%**
Out-of-Scope	**10%**	**5.25%**	**5.25%**

(Yellowknife Argument, p. 6)

In its argument, NUL stated:

> "…Northland is of the view that the proposals reflected in its application are the minimum required in order to attract and retain the necessary complement of employees during the test period. Northland submits that it is simply not reasonable to assume that in-scope employees will only

require an increase of 5.25% in 2010 as part of the new Collective Bargaining Agreement. The average increase over the current two year agreement is 8.125% and, if anything, Northland's 2010 forecast of 6% can be considered as being modest in light of the continuing "hot" labour market that is forecast to continue in southern markets well past 2010.

Likewise, the City of Yellowknife's recommendation that the percent increase for out-of-scope employees for 2009 and 2010 be limited to the level set for in-scope employees is not fair or reasonable. During cross-examination the City of Yellowknife acknowledged that out-of-scope employees perform management functions and assume management responsibilities that are not assumed or performed by in-scope employees. The City also acknowledged that generally management employees have a higher pay than in-scope employees. Northland submits that the failure to recognize these differences, and grant the increases requested in its application, will result in the pay scales of in-scope and out-of-scope employees being compressed, with the result that Northland would have considerable difficulty attracting the small number of out-of-scope employees required to run its company. Northland submits that the forecast inflation assumptions for labour contained in its application are reasonable and should be approved by the Board, as filed." (NUL Argument, p. 6-7)

Yellowknife responded to NUL in its reply argument.

"… The 11% in 2008 consisted of a market adjustment up to the level of ATCO Electric wages plus 5.25%. YK submits it is inappropriate to use the average of 8.125% which included a market adjustment. There is no evidence on the record that there will need to be another market adjustment in 2010 nor that the market will be even tighter in 2010 than it was in 2008. Further, as noted in Mr. Bruggeman's evidence, the CPI is forecast to remain relatively flat from 2008-2012. Finally, as noted in Mr. Bruggeman's evidence and in Argument, the settlement package also provided for increases in the designated community allowance and one additional flight out of the north per year which translated to an additional 6.6% and 2.4% on labor expenses.

NUL goes on to suggest that the City acknowledged that out-of-scope employees perform management functions and assume management responsibilities not assumed or performed by in-scope employees and that management employees have higher pay. NUL asserts that the failure to recognize these differences will result in compression of pay between in-

> scope and out-of-scope. YK addressed this in part in Argument at page 6 but would add the following. First, both groups were brought up to market in 2008 and therefore the relative levels of pay should be in line with duties in 2008. Second, given the higher pay levels for in-scope as noted by NUL in Argument, equal percentage increases in pay will result in the differentials widening rather than compressing." (Yellowknife Reply, p. 3-4)

In its reply argument, NUL again asserts that Yellowknife is ignoring the 8.125% increase over the two-year agreement. NUL also states that it is not reasonable to assume that NUL will be able to conclude another agreement at the same level as the last year of the previous agreement. NUL argues that demands for and compensation paid to skilled employees have increased. NUL also repeats its argument that holding the out-of-scope employees to the same increase as the in-scope employees would result in compression issues that would make it difficult to attract and retain the necessary management resources.

Views of the Board

The Board agrees with Yellowknife that NUL has not provided the evidence to justify the forecast 6% increase for in-scope employees in 2010. The Board also finds NUL's use of the 8.125% average increase over the two years of the agreement to be misleading due to the market adjustment in 2008. NUL has not provided sufficient evidence that another such adjustment will be required or that an increase above 5.25% is required for 2010.

For the out-of-scope employees, the Board also agrees with Yellowknife on the issue of salary compression. The same percent increases for out-of-scope and in-scope employees will result in the salary gap between these employees widening, not compressing. NUL has not justified the 2009 and 2010 increases for the out-of-scope employees being higher than the in-scope employees.

The Board directs that, in its Phase 1 refiling, NUL is to use the following inflation amounts for employees:

- In-scope 11% in 2008, 5.25% in 2009 and 5.25% in 2010
- Out-of-Scope 10% in 2008, 5.25% in 2009 and 5.25% in 2010

6.1.2 Other Inflation

NUL is forecasting an inflation rate of 5% for “Other” O&M expenses. Yellowknife argues that simply applying a single inflation rate to all “Other” expenses results in an overestimate of the inflation rate for certain components of “Other”. Yellowknife argues that operating materials and supplies should be inflated using the March 2008 Statistics Canada Consumer Price Index (“**CPI**”) of 3.2% instead of the 5% used by NUL.

In its argument, NUL states that its experience regarding things such as material and supplies and contractor services is that the inflation rate has been at levels far above the 5% forecast for NUL and that the forecasted 5% is necessary to cover costs.

Yellowknife replied by explaining that its recommendation of a 3.2% inflation rate is only for a specific component of “Other”, not “Other” as a whole. Yellowknife reiterates that it recommendation is for operating material and supplies.

NUL replies that it appears that the Yellowknife recommendation is focused on items which would have a very small impact on NUL’s operations and that the bulk of material costs have far exceeded that 5% inflation rate forecast by NUL.

Views of the Board

The Board finds that NUL has not adequately provided a response to Yellowknife's recommendation and appears to be confusing matters by bringing into the discussion items that would not be impacted by Yellowknife's recommendation.

In the absence of reasonable evidence to the contrary, the Board finds that the 3.2% inflation rate from the March 2008 CPI is a valid measure of increasing costs for NUL. The Board directs that, in its Phase 1 refiling, NUL is to apply an inflation rate of 3.2% to operating materials and supplies.

6.2 Affiliate Costs

6.2.1 Information Technology and Billing System Services

NUL receives information Technology services ("**IT**") and Information Technology Billing services ("**ITBS**") from ATCO I-Tek ("**I-Tek**") an affiliate of NUL. The terms under which NUL and other ATCO Utilities receive services from I-Tek are governed by a Master Services Agreement between I-Tek and the various ATCO Utilities.

The prices for IT and ITBS services paid by NUL and other ATCO utilities for the period 2003 to 2007 were the subject of a collaborative benchmarking process before the Alberta Utilities Commission ("**AUC**"). The prices determined in the benchmarking process were then adjusted pursuant to an Evergreen Strategy Report to arrive at IT and ITBS prices for 2008 and 2009 for the various ATCO Utilities. The prices for 2008 and 2009 determined under the Evergreen Strategy Report have not received approval by the AUC and are currently before the AUC for approval.

Having regard to the results of the Evergreen Strategy Report, NUL updated the placeholder amounts regarding IT and ITBS costs it had initially filed for the test years 2008 to 2010 by way of Exhibit 7, Response to YK-NUL10b). Since 2010 is not covered by prices under the Evergreen Strategy Report the prices for 2010 in the update reflect NUL's estimates of cost increases for IT and ITBS services in 2010. NUL stated it no longer sees the need for these updated amounts to be placeholders. This will avoid the need for any further regulatory processes relating to these costs.

Yellowknife noted the revised I-Tek costs are down 13% on average and the revised I-Tek Business Services ("**I-TekBS**") costs are down 8% on average.

Yellowknife submitted based on a 2007 Fair Market Value ("**FMV**") rate of $132.37 per month for laptop hardware operating lease, the updated amounts in, YK-NUL-10(b) Attachment 1 reflect reductions of 3%, 4% and 0% in 2008, 2009 and 2010. Yellowknife submitted there should also be a 4% reduction in 2010

Yellowknife noted Laptop Support High was forecast to increase 1% to 5% in the Evergreen Report. Based on a 2007 FMV rate of $147.79 per month, the updated amounts increased 3%, 6% and 7% in 2008, 2009 and 2010, or slightly above the range.

Yellowknife submitted server storage was forecast to decline by 25% per year in the Evergreen Report and based on the updated amounts, declined by 25%, 25% and 0% in 2008, 2009 and 2010. Yellowknife submitted there should also be a 25% reduction in 2010.

Yellowknife also expressed some concerns regarding the increases in Oracle Financial Hosting which increased from $29,000 in 2006 to $42,000 in 2010 with increases of 12% in 2009 and 16% in 2010. Yellowknife stated that these increases were attributed to labor support for these services from I-Tek. Yellowknife submitted that there is no evidence on the record to support 12% and 16% increases in labor from I-Tek and therefore these amounts should be reduced to the 5.25% forecast by NUL for its own employees in 2008 and 2009 and the 5.25% recommended by the City for 2010.

Although the revised IT amounts filed in YK-NUL-10(b) Attachment 1 tend to more or less comport to the Evergreen Report, Yellowknife noted that the Evergreen Report will be subject to review in AUC Application No. 1577426 29 and the initial filing of the Application is now not expected to occur until August 29, 2008. Under these circumstances, Yellowknife submitted that the IT placeholders as updated in the Rebuttal Evidence should remain as placeholders until the AUC finalizes the Evergreen Applications.

With respect to base billing services, Yellowknife stated it appears that NUL has applied inflation to determine the 2008 and onward fees for Base Billing Service based on negotiations with ITBS which is contrary to the findings of the Benchmarking Report. Yellowknife submitted that the FMV charge for Base Billing Services should be $1.52 per site per month.

With respect YK's recommendation that there should be a 4% reduction in 2010 for laptop operating lease, NUL stated the Evergreen Report does not indicate that decreases will continue indefinitely and YK's assertion is not supportable.

With respect to server storage in 2010, NUL stated the best information available to NUL is that price would remain flat for 2010.

With respect to increases to Oracle Financial hosting, NUL indicated labour charges are not the only factors driving the increases. The increases are also caused by items such as increased storage requirements as well as planned upgrades. It would, therefore, be inappropriate to restrict the increases to labour inflation only.

With respect to Yellowknife suggestion that the prices be placeholders until AUC approval, NUL stated information regarding these costs have now advanced to the point where they can and should be finalized in the context of the current GRA. This would avoid costs associated with further regulatory process and allow these matters to be finalized.

With respect to the base billing services charge, NUL stated the $1.52 recommended by Yellowknife represents a five year rate established in 2003, which was not inflated over that time period. In the Evergreen strategy report it is stipulated cost of living adjustment ("**COLA**") was not applicable to customer care and billing ("**CC&B**") services. Contracts for CC&B services tend to be for terms of five years and the proposed $1.72 per site per month billing services charge is a fixed price for 5 years. NUL indicated it has negotiated a new contract in 2008 which limits COLA adjustments to the labour components of services.

Views of the Board

The Board has examined the argument of Yellowknife and NUL respecting the costs for laptop operating lease in 2010 and server storage in 2010. The Board accepts as reasonable NUL’s explanation for not giving effect to further reductions in 2010 following the reductions to these costs in 2008 and 2009.

With respect to Oracle financial hosting, the Board notes NUL’s explanation that the increases are caused by labour cost increases, increased storage requirements as well as planned upgrades. While these explanations appear satisfactory for 2008 and 2009 which years are supported by the Evergreen Report the Board is concerned by the 16% increase in Oracle financial expense in 2010 over 2009. The Board has not seen convincing evidence to show why a 16% increase is warranted in 2010 following a 12% increase in 2009. The Board considers that a 3.2% increase in 2010 for Oracle financial hosting would be more in line with general price increases. Accordingly, the Board directs NUL to limit the increase in the Oracle Financial expense to 3.2% for 2010 and reflect this finding in the refiling application.

With respect to the base billing charges, the Board notes the $1.72 per site per month is a flat rate charge applicable over a five year period. The Board considers the use of a flat rate over the 5 year period results in a degree of front end loading of costs in the early years of the 5 year period and is not consistent with the principle of matching each year’s costs with the corresponding recovery. Accordingly, for regulatory purposes the Board considers each year’s charge should reflect the escalation applicable to that year, rather than the average for the 5 years. The following table shows how the 5 year charge of $1.72 may be adjusted so that each year’s charge reflects the escalation applicable to that year.

Escalation	5%
2008	1.56
2009	1.64
2010	1.72
2011	1.80
2012	1.89
Average	1.72

NUL is directed to escalate the base billing charge using a rate of 5% over the 5 year period so that the average of the rate over that period amounts to $1.72 and, to reflect this change in the refiling of the application.

Subject to the above noted change, the Board accepts the remaining updated IT and ITBS charges for the test period.

6.2.2 Regulatory and Financial Reporting

Yellowknife identified the regulatory Phase I and financial reporting charges from ATCO Electric, to be as follows:

	$000
2005A	143
2006A	166
2007A	201
2008F	270
2009F	277
2010F	296

Yellowknife noted from NUL's evidence that these charges are based on the level of support for the 2008-2010 GRA, the anticipated 2011 filing and increased financial reporting charges; the estimated time is amortized over the three year period and translates to 1.8 FTE's per year.

Yellowknife submitted that the previous GRA filing was quite similar in that it involved preparation of the 2005/2006 GRA, the preparation of the current GRA during 2007 and financial reporting; however the costs increased from an average of $170,000 per year to an average of $281,000 over the three test years or +65%. Yellowknife submitted based on 10% wage increases in 2008 and 5% in each of 2007 and 2009, ATCO Electric is still charging some 36% more time to NUL. Although financial reporting requirements have increased in recent years, the CEO/CFO certification began in 2005 and implementation was largely completed by 2007. Yellowknife submitted these types of costs should already be built into the base 2005-2007 costs.

Yellowknife submitted that Regulatory Phase I and Financial Reporting costs included in NUL's forecast revenue requirement should be reduced by $85,000 in 2009 and $94,000 in 2010.

NUL submitted, the charges by Regulatory Phase I and Financial Reporting, which are basically performed by the same staff, have been estimated based on the level of support required over the entire test period. The main filings are the 2008-2010 GRA, annual 25 kV deferral application, as well as support required for the 2011 filing.

NUL submitted this estimated time to support these filings is then amortized evenly over this three year test period to avoid undue rate spikes in any given year. This estimate has resulted in approximately 1.8 FTEs being allocated to NUL during the test period.

NUL submitted that the level of financial reporting support is increasing with the upcoming changes to International Financial Reporting Standards ("**IFRS**"). NUL submitted, given that the current regulatory workloads include this GRA, as well as support for the 2011 GRA, and increased financial reporting requirements, the regulatory Phase I and financial reporting charges in the test period are reasonable.

Views of the Board

The Board notes NUL's evidence that the level of financial reporting support is increasing which includes the upcoming changes to IFRS. Having regard to the workload in the 2008 to 2010 period the Board accepts NUL's forecast of Regulatory Phase I and Financial Reporting costs for purposes of this Decision.

6.3 Rate Case Costs

NUL has estimated a $400,000 cost for the current GRA (Phases 1 and 2). Combined with the remaining balance of $29,000 from the previous GRA, the total rate case cost of $429,000 results in a 3-year amortization of $143,000 per year with no balance remaining at the end of 2010.

The $400,000 estimate for the current GRA is based upon the $238,000 cost for the previous GRA with additional costs for having a full hearing instead of a negotiated settlement, extra costs for expert cost of capital evidence, extra costs for preparing a sales forecast study and reduced costs for no depreciation study.

During cross-examination by Yellowknife, NUL confirmed that its costs for legal counsel would be in the $600/hour range and its costs for the cost of capital expert would be in the $300/hour range. NUL also indicated that its total estimate for the expert cost of capital evidence was $100,000 and about $30,000 had been billed at the time of the hearing.

Yellowknife stated the following in its argument.

> "Even if the Board accepts Ms. McShane's hourly rate in the three hundred dollars ($300) per hour range as just and reasonable, given the costs to date of the hearing and the extent of Ms. McShane's involvement at the hearing, the City considers it likely that the $100,000 estimate for Ms. McShane's evidence was over-forecast and a more reasonable forecast would be in the range of $50,000.
>
> ….
>
> NUL has included $143,000 for each of 2008, 2009 and 2010 for the amortization of the $400,000 for this rate case plus the unamortized balance from previous proceedings. In light of the hourly rates for consulting and legal fees incurred by NUL, it would appear to the City that the full amount of costs included in this forecast is unlikely to found to be just and reasonable.
>
> While the City is aware that the Board does not have a formal scale of costs, Decision 15-2007 suggests that the Board may have a de facto reasonable limit for the hourly rates for expert consultants. The City notes that the two hundred fifty dollar ($250) per hour rate imposed by the Board in Decision 15-2007 is the same level currently in force in the Alberta Utilities Commission's Scale of Costs as set out in its Rule 022 for both consultants and senior counsel. While recognizing that the AUC's scale of costs is under review and appears to be significantly out of date, the City expects that the Board may consider legal costs in the $600 per hour range to exceed what is just and reasonable.
>
> NUL pointed out that the forecast in question is a "trueup account" and the City certainly acknowledges that. However, the City would point out that historically, although the Board has afforded utilities the opportunity to comment on cost claims submitted by intervenors, the reverse has not been the case. Further, it is trite that a trueup account should be as accurate as possible, to minimize the magnitude of any eventual adjustment.
>
> **Accordingly, in light of the evidence of the forecast costs for Ms. McShane's involvement, her costs to the date of the hearing, and the hourly rates for NUL's legal counsel and consultants, and in recognition of the Board's statutory discretion over costs, the City**

> **recommends that this forecast be decreased to $300,000 from the $400,000 forecast by NUL. The City has no concerns regarding NUL's proposed equal amortization of these costs over the three test years but would recommend that the amount to be amortized be set at $300,000. The City would also recommend that in the interests of equitable treatment, the Board afford it an opportunity to comment on the cost claim submitted by NUL, just as it has historically given the utility the opportunity to comment on the cost claims submitted by intervenors.**" (Yellowknife Argument, p. 11-13)

NUL responded to Yellowknife in its reply argument.

> In its Argument the City of Yellowknife arbitrarily requests that the consulting costs for ATCO Electric's expert witness be reduced by 50%. This recommendation totally ignores the fact that at the time of the proceeding the bulk of Ms. McShane's costs relating to testifying at the proceeding, preparing Argument and Reply and engaging in activities such as witness preparation had not been factored into the costs incurred. Northland submits that its estimate of costs for expert consultants is reasonable and should be approved.
>
> While the City acknowledges that the Board does not have a formal scale of costs it nonetheless arbitrarily seeks to deprive Northland of the costs reasonably incurred for the conduct of its GRA. Northland would observe that it conducts its GRA with the assistance of a single legal Counsel and, with the exception of an expert witness on capital structure/rate of return in this case, does not engage any outside consultants for any other aspect of its Application. Northland's use of experienced Counsel at prevailing market rates is reasonable and appropriate and the arbitrary reduction recommended by the City is simply not supportable.
>
> Additionally, the City's recommendation that it be afforded an opportunity to comment on the cost claim submitted by Northland is absolutely unnecessary. The Board should employ its normal process for the consideration and processing of cost claims and there is simply no reason to change the Board's traditional approach in the context of these proceedings.

(NUL Reply, p. 12)

Views of the Board

The Board finds the rate paid by NUL to its legal counsel to be excessive, particularly when considering the amount of revenue requirement and the level of complexity of NUL's GRA.

Section 26 of the *Act* is clear that the Board has full discretion over the level of costs in relation to a proceeding.

> 26. The costs of and incidental to a proceeding before the Board or any investigation made by the Board, including the costs of an interested person, are in the discretion of the Board and the Board may order by whom, to whom in what amount the costs are to be paid.

As noted by Yellowknife, while the Board does not have a formal scale of costs, the Board did indicate a level of costs ($250/hour) that it considers reasonable in Decision 15-2007. However, the Board is also aware that the AUC has recently issued an updated schedule of costs (Rule 009) which caps legal fees at $350/hr and expert fees at $270/hr. The Board accepts that these rates might be more reflective of the current market conditions than the $250/hr used by the Board in Decision 15-2007.

While the Board agrees that the $100,000 reduction recommended by Yellowknife appears to be arbitrary, when requested NUL did not provide the evidence required for Yellowknife to have prepared a non-arbitrary recommendation.

The Board also agrees with Yellowknife that the $100,000 estimate for cost of capital evidence seems excessive.

The Board directs that, in its Phase 1 refiling, NUL is to use a forecast cost for the current Phase 1 and 2 GRA that is the greater of the following 2 options:

1) the $238,000 cost of the previous GRA; or
2) an updated forecast cost of the current Phase 1 and 2 GRA with rates for NUL's legal counsel capped at $350/hr and the cost of capital expert capped at $270/hour.

If NUL proceeds with Option 2, then it will be expected to provide supporting evidence and calculations.

While the Board considers the above direction to a fair and reasonable balance of interests that will be applied to the current GRA, it is clear that the Board will need to develop a formal scale of rates to avoid such situations in the future.

The Board also agrees with Yellowknife that it would be fair for the interveners to have the opportunity to comment upon cost claims by NUL and other utilities regulated by the Board. To formalize such a procedure, the Board will be required to make an amendment to its *Rules of Practice and Procedure*. However making this change will not be sufficient for this proceeding. The Board directs that, within 90 days of the conclusion of the Phase 1 and Phase 2 GRAs, NUL will file a cost claim with the Board covering both Phase 1 and 2.

6.4 Pension Expense

NUL participates in both of the Canadian Utilities-sponsored pension plans: Plan 1 is a combined Defined Benefit ("**DB**") and Defined Contribution ("**DC**") plan (which is the plan NUL's parent ATCO Electric operates). NUL participates in the DC portion of Plan 1. Plan 2 is a DB pension plan and NUL participates in this plan.

Plan 1, the combined DC and DB pension plan, is currently in a surplus position, and as there are no funding requirements, there is currently a "pension holiday" i.e. there is no requirement to fund this plan using the cash method employed by NUL and ATCO Electric. Plan 2 was in a pension surplus position as at December 31, 2003 i.e. the last actuarial evaluation date, but is now in deficit position based on the most recent December 31, 2006 actuarial evaluation. The next such evaluation must be undertaken no later than December 31, 2009. NUL proposed a 27% funding requirement for Plan 2 for 2008, 2009 and 2010.

With respect to Plan 1, the City submitted to the extent NUL participates in Plan 1 [DB and DC] for its DC-eligible employees, customer rates are subject to changes in funding requirements resulting from fluctuations in actuarial values of DB-based pension plan assets and liabilities in Plan 1. On a stand alone basis, a DC plan would not be exposed to the vagaries of such market and actuarial fluctuations. Yellowknife recommended NUL should be directed, at its next GRA, to address the continued appropriateness of operating under the parent company Plan 1, which combines the DC and DB Plans.

With respect to Plan 2, Yellowknife did not object to the 27% funding rate for 2008 and 2009. However, since there will be an actuarial evaluation of the DB Plan 2 no later than December 31, 2009, Yellowknife submitted that any funding assumptions for 2010 are premature and therefore the pension expense for 2010 should be set to zero.

With respect to Plan 1, NUL submitted Northland received the benefit of the surplus in ATCO Electric's DB Plan 1 by way of a contribution holiday but the DC plan (Plan 1) will not have to fund any more than the 6% requirement should there no longer be any surplus in Plan 1.

With respect to Plan 2, NUL stated while the actuarial evaluation will be done for 2010 there is no expectation the funding requirements will be reduced for 2010.

Views of the Board

Based on NUL's explanation, the Board is satisfied neither the Plan 1 DC plan nor the customers of NUL will be disadvantaged if there is a funding shortfall within the DB component of Plan 1. With respect to Plan 2, the Board notes NUL's assertion there is no expectation the 27% funding level will be reduced in 2010. Accordingly, the Board will not accept Yellowknife's recommendations respecting the appropriateness of a combined DC and DB Plan 1 and the pension expense for 2010.

6.5 Defined Benefit and Contribution Pension Plans Cash Contribution Deferral Account

NUL stated the following in Section 1 of its Application:

> Beginning in 2010, Northland is seeking a deferral account to flow through increases or decreases to required cash contributions to the company's defined benefit and contribution pension plans. The timing of this request is based on the need for an updated actuarial valuation for pension funding for the year beginning January 1, 2010. In addition, Northland is proposing this deferral account flow through the impact, if any, the 2010 pension valuations will have on the affiliate labour expense charged for Whitehorse and Alberta based support services. The details of this deferral account are discussed in Section 4.
>
> (GRA Section 1, p. 1-6)

Yellowknife did not raise any concerns with this proposed deferral account.

Views of the Board

The Board has not identified any concerns with the proposed deferral account. The Board approves the use of the Defined Benefit and Contribution Pension Plans Cash Contribution Deferral Account as proposed by NUL.

7. DEPRECIATION

Depreciation is discussed in Section 6 of NUL's Application. NUL forecasts depreciation expenses of $1.670 million, $1.883 million and $2.152 million for test years 2008, 2009 and 2010, respectively.

NUL proposed to continue using the existing depreciation rates for the test period. No issues were raised by Yellowknife respecting depreciation.

Views of the Board

The Board accepts NUL's proposed method of calculating depreciation for the purposes of this Decision.

8. INCOME TAXES

8.1 Income Tax Rate Variance Deferral Account

The City submitted NUL's 2008-2010 tax calculation reflects the use of the most recently enacted federal and territorial statutory corporate income tax rates. The City noted NUL proposes an income tax deferral account commencing 2008 only for changes in the enacted federal and territorial income tax rates, but not for any other tax-related changes

The City submitted based on Mr. Merani's evidence filed in these proceedings, there is sufficient evidence and grounds for directing NUL to set up a deferral account, effective January 1, 2008, to account for all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) from those reflected in the determination of the Test Year Revenue Requirements. The City submitted a similar deferral account has been approved for ATCO Electric by its regulator. The City submitted neither NUL shareholders nor customers should be at risk for changes arising from legislation related to income taxes as these changes are beyond the control of utility management

NUL submitted there are no proposed income tax changes that are not substantially enacted which are expected to occur during the test period. Further, NUL noted, even if CCA changes that have been around for a considerable period of time were implemented during the test period the result would be de minimus.

Views of the Board

The Board notes NUL has proposed an income tax deferral account for changes in income tax rates. This means NUL would be shielded from any gain or loss resulting from changes in statutory income tax rates with respect to the test period. Since a deferral account for income tax rates has already been proposed by NUL including all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the deferral account would be consistent with the purpose of the income tax deferral account proposed by NUL. Accordingly, the Board directs NUL to include all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the income tax deferral account.

8.2 Deductions

The City submitted the Canada Revenue Agency ("**CRA**") has allowed immediate tax deductions in respect of certain capital repair costs which, for accounting purposes, are capitalized under Canadian GAAP, but which may be claimed as immediate tax deductions. Such tax deductions are generally referred to as "Rainbow-type tax deductions.

The City submitted certain capital repair costs namely pole test and treat are being expensed by NUL for accounting purposes as well as for tax purposes whereas this type of expenditure should be capitalized under GAPP and claimed as Rainbow-Type deductions for tax purposes. The City noted these types of expenses are being capitalized by NUNWT for accounting purposes. The City submitted, if material, such expensed capital repair costs could result in large swings in O&M expenses, making comparability over time more difficult. The City submitted the Board direct NUL to cease its practice of expensing these capital-repair costs and treat them as being eligible for the Rainbow tax deductions as part of its GRA Refiling.

The City also submitted it is difficult to believe NUL does not, or will not, treat as Rainbow-Type deductions for tax purposes expenditures such as Distribution Line Relocations, System Improvement Planning, Safety and Environment and Right of Way repairs which are taken as deductions for tax purposes by NUL's parent ATCO Electric.

With respect to the expensing of the pole test program, NUL stated given the materiality of the costs ($15,000) and given that this has been treated in a consistent manner, there is no need for a change in accounting treatment.

With respect to other Rainbow-Type deductions, NUL stated the company examines the Rainbow criteria to assess whether any of its projects qualify for such deductions as part of preparing for its filing. Further study is therefore not required. The majority of NUL's capital costs are for new extensions and distribution improvements. NUL submitted, in its view these expenditures are of an enduring benefit to the system and are being treated appropriately by NUL. NUL stated further, since line moves are 100% covered by contributions there is no issue respecting deduction of these items as Rainbow-Type deductions.

Views of the Board

The Board agrees with the City that the expensing of capital repair costs such as pole test and treat expenditures, is not consistent with Canadian GAPP.

Accordingly, the Board directs NUL to capitalize pole test and treat expenditures for accounting purposes and claim these expenditures as Rainbow-Type deductions for income tax purposes for each of the test years, as part of the Phase I refiling.

With respect to other Rainbow-Type deductions, the Board accepts NUL's explanation that it examines the Rainbow criteria to assess whether any of its projects qualify for such deductions as part of preparing for the filing. The Board will therefore not require NUL to undertake a further study of expenditures eligible for Rainbow-type deductions.

Given the Board's direction respecting treatment of pole test and treat expenditures as Rainbow-Type items the Board considers it appropriate to include a deferral account for Rainbow-Type deductions. Such a deferral account would be consistent with a similar deferral account requested by Northland (NWT) Limited. The Board directs that NUL set up a deferral account for Rainbow-type deductions for the test period.

8.3 ES&G Charges

8.3.1 Stock Handling Charges

The City recommended the Board direct NUL to include in its Refiling the incremental ES&G amounts related to the stock handling charges identified in Exhibit 12 as additional tax deductions for the Test Years 2008-2010. In addition, the City submitted NUL should be directed to refile its prior income tax returns in respect of stock handling charges and flow the resulting tax savings to customers in its next GRA.

With respect to the City's submission that NUL be directed to refile its prior income tax returns in respect of stock handling charges and flow the resulting tax savings to customers in its next GRA, NUL submitted the City's suggestion amounts to retroactive ratemaking which is not permissible.

Views of the Board

The Board notes NUL's treatment of stock handling charges for income tax purposes was different prior to the current test period. Prior to the current test period stock handling charges were not deducted for calculation of the income tax component of revenue requirement, both in the forecasts and in the actuals. As long as NUL's treatment of stock handling charges remains consistent for the forecasts as well as actuals, the Board considers customers will not be harmed. However, if NUL were to choose to follow the route of ATCO Gas and request that its prior year income taxes be reassessed by CRA to the maximum extent possible including deduction for stock handling charges then customers will be harmed if such charges were not were not flowed through to customers.

In view of the foregoing, the Board will not direct NUL to retroactively adjust its deductions for stock handling charges respecting prior years. However, if NUL were to choose to request such deductions from CRA respecting prior years, the Board expects that any resulting income tax savings will be flowed through to NUL's customers.

8.3.2 Level of ES&G Charges

The City submitted in 2007, NUL incorporated a change in accounting policy such that there has been a significant reduction in the total amount of ES&G

expenses. For example, in 2006A the total ES&G was $271,000 whereas in 2007F, it is $115,000, about 60% less. The City stated a closer examination suggests NUL has significantly decreased the ES&G associated with Salaries and Wages due to “engineering support staff now charging their time directly to capital work in accordance with company policy and CRA guidelines. The effect of this change in accounting policy, which has not been approved by the Board, is to significantly reduce the ES&G tax deductions otherwise available.

The City submitted NUL has provided no evidence in support of its proposed change to company policy reflecting a significant reduction in ES&G. More specifically, the practice of charging engineering support staff labour costs which cannot be identified with any particular capital work order has been in place to date, and there is no indication that the CRA has rejected any claims so made.

The City noted in both 2005 and 2006 on an actual basis, NUL has claimed significantly more ES&G than the Board-approved forecast amounts on account of increased labour costs being charged to ES&G.

NUL submitted the advice from its tax experts within the ATCO Group is that the policy of charging to ES&G those people who work directly on capital projects, but for administrative ease were charging to ES&G, would not fall within the realm of what is allowable from a CRA perspective.

Views of the Board

The Board notes NUL’s argument that the reduction in ES&G is due to the change in the previous practice of charging salaries of individuals who work directly on projects, but for administrative ease were charging to ES&G. Under the new practice, the salaries of such individuals would be charged directly to capital projects. The Board accepts NUL's explanation for change in ES&G capitalization policy for purposes of this Decision.

The Board notes the City's concern respecting materially higher amounts being charged to ES&G on an actual basis compared with the forecasts in 2005 and 2006. The Board will be concerned if differences between forecast and actual ES&G were the result of changes in the policy respecting capitalization of ES&G. The Board directs NUL, in future proceedings, to provide explanations for material variances between forecast and actual capitalized ES&G levels.

9. SALES AND REVENUE FORECAST

The sales forecast by customer class is provided in Schedule 2 of NUL's application. NUL is forecasting total energy sales 160,808 MW.h, 160,486 MW.h and 161,289 MW.h for test years 2008, 2009 and 2010, respectively.

9.1 Residential Use Per Customer

Residential sales constitute about 35% of NUL's overall sales. The residential sales forecasts for the test years are based on the forecast number of customers and the temperature normalized average use per residential customer. NUL's forecast of residential average use per customer ("**UPC**"), based on regression analysis, for each of the test years is as follows:

	Average Use Per Customer kwh
2008	8148
2009	8017
2010	8017

NUL stated, with the exception of 2005, nearly two-thirds of all new housing developments in Yellowknife during 2001-2007 (2007, year-to-date) were in multi-family dwellings. As multi-family dwellings generally use less energy because of a smaller size relative to single family houses, their increased share in the housing mix in Yellowknife has contributed to a downward trend in the average residential energy use into the test years.

Mr. Bruggeman, witness for Yellowknife, disagreed with NUL and argued that the decline in residential UPC calculated by NUL for the test years assumes that the large number of multi-family unit additions will continue to influence the UPC trend. Mr. Bruggeman noted not only are residential additions forecast to decline significantly, but a review of the forecast capital additions shows few if any multi-family additions in the test years. After the last major multi-family addition in 2005, the normalized UPC began to flatten out in 2006 and 2007. Mr. Bruggeman noted the downward trend in 2006 and 2007 is an indication of energy savings attributable to renovations and improvements of existing homes and appliances.

Mr. Bruggeman recommend that the 2006-2007 trend be extended through the test period and accordingly, residential UPC would decline by 30 kWh per year for average Residential UPC of 8,319 kWh, 8,289 kWh and 8,259 kWh for 2008, 2009 and 2010.

Views of the Board

The Board recognizes, in a relatively small community with close to 7000 residential customers, the number of Multi-family unit additions can have an impact on the trend for residential consumption. The Board notes Mr. Bruggeman’s evidence that Multi-family unit additions have leveled off after 2006. A leveling off of Multi-unit construction post 2006 means the rate of decline in UPC may not be as high after 2006 as it was before year end 2006. This means an increment of one in the trend variable as reflected in the regression model for each month of the forecast period may not properly capture the leveling off of Multi unit additions during the test period. However, the Board recognizes it is not only the multi unit dwellings that affect the trend variable. There are also the energy saving contribution from the addition of new houses and the new generation of energy savings appliances used in these houses. In addition the trend variable would reflect the impact of energy savings related to improvements and renovations of existing homes and appliances. In view of these types of continuing energy savings it is also inappropriate to assume the trend variable will be flat over the test period.

The Board notes NUL's concern over the use of only two years of data to estimate the impact of the trend as recommended by Mr. Bruggeman. The Board agrees the use of only two years of data is unlikely to provide reasonable estimates of the trend in UPC during the test period. NUL acknowledges while energy efficiency of new units and the high share of multi family units would contribute to further energy efficiency, this would occur at a smaller increment. (YK NUL 12d) However, NUL has not attempted to quantify this impact. On balance, the Board considers a 0.5 increment in the trend variable in each month (as opposed to an increment of 1 proposed by NUL) during the test period would capture the impact of normal conservation during the test period. The following table shows the Board's estimation of the annual residential UPC using a trend variable which increments by 0.5 each month instead of 1. All other regression statistics proposed by NUL remain the same.

Determination of Annual Residential UPC

Month	Normal Monthly Heating Degree Days	Trend Variable Per NUY	January Dummy Variable	UPC Per NUY	Annual UPC Per NUY	Trend Variable Per Board	UPC Per Board	Annual UPC Per Board
Jan/08	1,360	169.00	1	980		168.50	980	
Feb/08	1,150	170.00	0	779		169.00	779	
Mar/08	1,072	171.00	0	760		169.50	761	
Apr/08	694	172.00	0	673		170.00	675	
May/08	419	173.00	0	609		170.50	611	
Jun/08	139	174.00	0	544		171.00	547	
Jul/08	56	175.00	0	524		171.50	528	
Aug/08	127	176.00	0	540		172.00	543	
Sep/08	319	177.00	0	583		172.50	587	
Oct/08	606	178.00	0	647		173.00	652	
Nov/08	939	179.00	0	722		173.50	727	
Dec/08	1,227	180.00	0	787	**8,148**	174.00	793	**8,183**
Jan/09	1,360	181.00	1	969		174.50	975	
Feb/09	1,150	182.00	0	768		175.00	774	
Mar/09	1,072	183.00	0	749		175.50	756	
Apr/09	694	184.00	0	662		176.00	669	
May/09	419	185.00	0	598		176.50	606	
Jun/09	139	186.00	0	533		177.00	542	
Jul/09	56	187.00	0	514		177.50	522	
Aug/09	127	188.00	0	529		178.00	538	
Sep/09	319	189.00	0	572		178.50	581	
Oct/09	606	190.00	0	636		179.00	646	
Nov/09	939	191.00	0	711		179.50	722	
Dec/09	1,227	192.00	0	776	**8,017**	180.00	787	**8,118**
Jan/10	1,360	181.00	1	969		180.50	969	
Feb/10	1,150	182.00	0	768		181.00	769	
Mar/10	1,072	183.00	0	749		181.50	750	
Apr/10	694	184.00	0	662		182.00	664	
May/10	419	185.00	0	598		182.50	600	
Jun/10	139	186.00	0	533		183.00	536	
Jul/10	56	187.00	0	514		183.50	517	
Aug/10	127	188.00	0	529		184.00	532	
Sep/10	319	189.00	0	572		184.50	576	
Oct/10	606	190.00	0	636		185.00	641	
Nov/10	939	191.00	0	711		185.50	716	
Dec/10	1,227	192.00	0	776	**8,017**	186.00	782	**8,052**

Regression Statistics:

Intercept	670.329
Degree Days	0.22819
Trend Variable	-0.9068
Dummy Variable	152.334

The Board considers the UPC adjusted for the leveling off of Multi unit additions as set out in the above table provides a fair estimate of UPC for each of the test years. Accordingly, the Board directs NUL to adjust its residential sales forecast to reflect UPC of 8183 kWh in 2008, 8118 kWh in 2009 and 8052 kWh in 2010 in its refiling Application.

9.2 Non-Residential Sales Forecast

Sales to the commercial class are forecast to increase 0.6% in 2007 and a further 3.5% in 2008, as several new commercial customers, including a Staples and a Shoppers Drug Mart, join the existing customers. In 2009 and 2010, sales are forecast to increase by 0.2% and 0.4%, respectively. These increases are primarily due to new commercial customers such as the Twin Pines Hotel, the WCB Building and the Courthouse.

NUL indicated, consistent with the methodology used in the past, the commercial energy sales forecast is obtained through a two step process. First, the energy sales of existing customers are calculated using a three-year historical average UPC multiplied by the current customer count. Next, the energy forecast is adjusted by the additions/deletions of large customers. Each new commercial customer is considered individually to determine the load they will bring to the system. NUL relied on information collected from its customers, the City of Yellowknife and local developers as well as the energy needs of existing customers which have a similar profile to the new customer being considered. The additional load for the new customers was added to the base energy sales forecast to arrive at the total load for the commercial customer class.

The energy forecast for street and sentinel lighting is based on a three-year historic average of light additions. The forecast also considers projects identified for the coming years, such as new subdivisions or areas that the City of Yellowknife has identified as requiring lighting.

The Board notes Yellowknife withdrew the recommendations in its filed evidence respecting certain changes to NUL's commercial energy sales forecast.

Views of the Board

The Board accepts NUL's forecast of non-residential energy sales for purposes of this Decision.

10. Other Matters

10.1 Taxes Other Than Income

The taxes other than income are the franchise fee and property taxes.

The franchise fee is paid to the City of Yellowknife based upon the Franchise Agreement which grants NUL the exclusive rights to distribute electricity to the City and its residents. The franchise fee is forecast to be $772,000, $790,000 and $807,000 for the test years 2008, 2009 and 2010, respectively.

The property taxes are paid to the City semi-annually for NUL's office building, substation properties and power lines. The property taxes are forecast to be $831,000, $850,000 and $869,000 for the test years 2008, 2009 and 2010, respectively.

Yellowknife had no comments in its argument regarding purchased power expense.

Views of the Board

The Board has not identified any concerns with taxes other than income for the test years. The Board approves the taxes other than income for the test years as proposed by NUL.

10.2 International Financial Reporting Standards (IFRS)

With respect to the introduction of IFRS, NUL stated as follows:

> "On February 13, 2008, the Canadian Accounting Standards Board confirmed that IFRS will replace Canadian GAAP for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Comparative information based on IFRS to be included with the 2011 financial statements will have to be collected beginning in 2010. To date the ATCO Group of companies has completed the following in preparation for these deadlines: appointed a Steering Committee, assigned a Project Manager, developed an Implementation Working Group comprised of senior financial employees from each of the operating companies, hired an external consultant to assist with the conversion, identified the key differences between IFRS and Canadian GAAP, and provided IFRS training to key employees." (YK NUL 6a)

The City submitted the IFRS convergence project has the potential of having wide-ranging and potentially far-reaching cost impacts on customers. NUL should be directed to provide to the NWT Board and interveners the same information its parent ATCO Electric (either by itself or through the ATCO Group) will provide in response to the AUC's May 23, 2008 letter, identifying all impact(s) specific to NUL. A process should also be established for customers to provide feedback, as necessary, to the proposals advanced by NUL for it to be compliant with IFRS, particularly where such proposals involve accounting and regulatory changes which have a potentially significant impact on customer rates.

NUL submitted a formal process as has been established before the AUC should not be required as time and expense can be avoided by simply advising the Board of what is occurring regarding this matter. NUL stated, given the potential that a significant amount of resources may be required to address this issue, a process whereby NUL would provide updates to the Board (perhaps in the 25kV deferral account applications) should be sufficient to keep the Board and parties appraised of developments in this regard.

Views of the Board

The Board considers that a formal process as has been established before the AUC should not be required for NUL at this time. However, given the significance of the changes contemplated under IFRS, the Board considers it important that it be kept fully informed of any material changes in NUL's financial reporting as convergence towards IFRS proceeds. The Board directs NUL to provide such information to the Board and interveners on an as needed basis consistent with the Board's desire to be kept fully informed on developments respecting this matter.

10.3 Report of Finances and Operations

In the concurrent Northland Utilities (NWT) Limited GRA proceeding, one of the Interveners submitted that currently the company's annual reporting of its actual costs is limited to providing the Board with (i) a current list of directors and officers; (ii) rate schedules; and (iii) audited financial statements. The Intervener submitted the information provided is of limited value in that it does not provide the Board and interveners any rationale to assess the nature and extent of changes in actual costs relative to the forecast approved costs. Any assessment of trending or other such analyses is therefore significantly limited by the lack of this information.

Northland Utilities (NWT) Limited indicated it will file additional information similar to that currently filed with the Yukon Board.

Views of the Board

The Board expects NUL to file with the Board annual reports of finances and operations that are consistent with the reports filed by Northland Utilities (NWT) Limited.

11. SUMMARY OF BOARD DIRECTIONS

Phase 1 Refiling

1. The Board directs NUL to reflect the 2007 actual plant closing balances in the plant opening balances for 2008 in its Phase 1 refiling.

2. The Board determines a common equity ratio of 43.5% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

3. The Board directs that, in its Phase 1 refiling, NUL is to incorporate debt rates of 5.51% for 2008, 6.32% for 2009 and 7.05% for 2010 into its cost of debt calculation.

4. The Board directs that, in its Phase 1 refiling, NUL is to use the following inflation amounts for employees:

   - In-scope 11% in 2008, 5.25% in 2009 and 5.25% in 2010
   - Out-of-Scope 10% in 2008, 5.25% in 2009 and 5.25% in 2010

5. The Board directs that, in its Phase 1 refiling, NUL is to apply an inflation rate of 3.2% to operating materials and supplies.

6. The Board directs NUL to limit the increase in the Oracle Financial expense to 3.2% for 2010 and reflect this finding in the refiling application.

7. NUL is directed to escalate the base billing charge using a rate of 5% over the 5 year period so that the average of the rate over that period amounts to $1.72 and, to reflect this change in the refiling of the application.

8. The Board directs that, in its Phase 1 refiling, NUL is to use a forecast cost for the current Phase 1 and 2 GRA that is the greater of the following 2 options:

   1) the $238,000 cost of the previous GRA; or
   2) an updated forecast cost of the current Phase 1 and 2 GRA with rates for NUL's legal counsel capped at $350/hr and the cost of capital expert capped at $270/hour.

   If NUL proceeds with Option 2, then it will be expected to provide supporting evidence and calculations.

9. The Board directs NUL to capitalize pole test and treat expenditures for accounting purposes and claim these expenditures as Rainbow-Type deductions for income tax purposes for each of the test years, as part of the Phase I refiling.

10. The Board directs NUL to adjust its residential sales forecast to reflect UPC of 8183 kWh in 2008, 8118 kWh in 2009 and 8052 kWh in 2010 in its refiling Application.

Next Phase 1 GRA

11. The Board notes that by the end of 2010 NUL intends to have completed the AMR/meter conversion project. Assuming that this upgrade in the metering system would enable the separation of non-technical losses from the system loss calculation, the Board directs that, in the next Phase 1 GRA, NUL is to include an examination of the pros and cons of separating losses into its two components (technical losses and non-technical losses) and, if determined desirable to do so, to calculate and include these two components in its calculations for the next GRA.

Other Directions

12. The Board directs that, within 90 days of the conclusion of the Phase 1 and Phase 2 GRAs, NUL will file a cost claim with the Board covering both Phase 1 and 2.

13. The Board directs NUL to include all changes announced in any Federal and/or Territorial Budgets (i.e. related to corporate income tax and CCA rates) impacting income tax expense in the income tax deferral account.

14. The Board directs that NUL set up a deferral account for Rainbow-type deductions for the test period.

15. The Board directs NUL, in future proceedings, to provide explanations for material variances between forecast and actual capitalized ES&G levels.

16. The Board considers that a formal process as has been established before the AUC should not be required for NUL at this time. However, given the

significance of the changes contemplated under IFRS, the Board considers it important that it be kept fully informed of any material changes in NUL's financial reporting as convergence towards IFRS proceeds. The Board directs NUL to provide such information to the Board and interveners on an as needed basis consistent with the Board's desire to be kept fully informed on developments respecting this matter.

12. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NUL to provide to the Board and interested parties a Phase 1 refiling reflecting the findings and directions in this Decision within 30 days of the release of the Board's Phase 2 Decision.

2. The Board directs NUL to provide as part of the Phase 1 refiling a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.

3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northland Utilities (Yellowknife) Limited.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

Joe Acorn

____

Joe Acorn
Chairman

Dated October 27, 2007

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

EB-2007-0905

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 Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

NOVEMBER 3, 2008

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Appendices:

A- Procedural Details Including Lists of Parties and Witnesses

B- Approvals Sought by OPG in EB-2007-0905

C- Decision on Interim Payments in EB-2007-0905

D- Section 78.1 of the *Ontario Energy Board Act, 1998*, S.O.1998, c.5 (Schedule B)

E- Ontario Regulation 53/05

F- Memorandum of Agreement between OPG and the Province of Ontario

1 INTRODUCTION

This proceeding concerned an application by Ontario Power Generation Inc. (OPG) under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B) (*OEB Act*) requesting Board approval for payment amounts with respect to six hydroelectric generating stations and three nuclear generating stations owned and operated by OPG.

This was an unusual proceeding in at least two respects. First, until now the Board has not regulated the prices charged by electricity generators in Ontario. Second, regulations under the *OEB Act* constrain in some important respects the scope of the Board's consideration of OPG's application as compared to the scope of the Board's hearings on rates charged by transmitters and distributors.

This chapter briefly describes the generation facilities in question and summarizes OPG's application. It also describes the legislative framework that governs the Board's setting of payment amounts for OPG's facilities and how that framework affected this proceeding.

Details of the procedural aspects of this proceeding are contained in Appendix A.

1.1 The Prescribed Generation Facilities

OPG requested that the Board approve payment amounts for nine generating stations. These facilities, and their nameplate capacities, are listed in Table 1-1. These plants are referred to as the "prescribed generation facilities" under regulations to the *OEB Act*, and that term is used extensively in this decision. (OPG's other generating facilities are unregulated, including various hydroelectric and fossil fuel stations.)

The nine generating stations have a combined capacity of 9,938 MW, or about 45% of OPG's total generation capacity. The Sir Adam Beck Pump Generating Station, which is integrated with the Beck complex, provides the bulk of the peaking capability from OPG's regulated facilities. The other plants are "baseload" facilities although the other hydroelectric facilities have some minor peaking capability.

Table 1-1: Prescribed Generation Facilities

Hydroelectric		Nuclear	
Station	Capacity	Station	Capacity
Sir Adam Beck I	447 MW	Pickering A NGS	1,030 MW
Sir Adam Beck II	1,499 MW	Pickering B NGS	2,064 MW
Sir Adam Beck Pump Generating Station	174 MW	Darlington NGS	3,512 MW
DeCew Falls I and II	167 MW		
R.H Saunders	1,045 MW		
Total	**3,332 MW**		**6,606 MW**

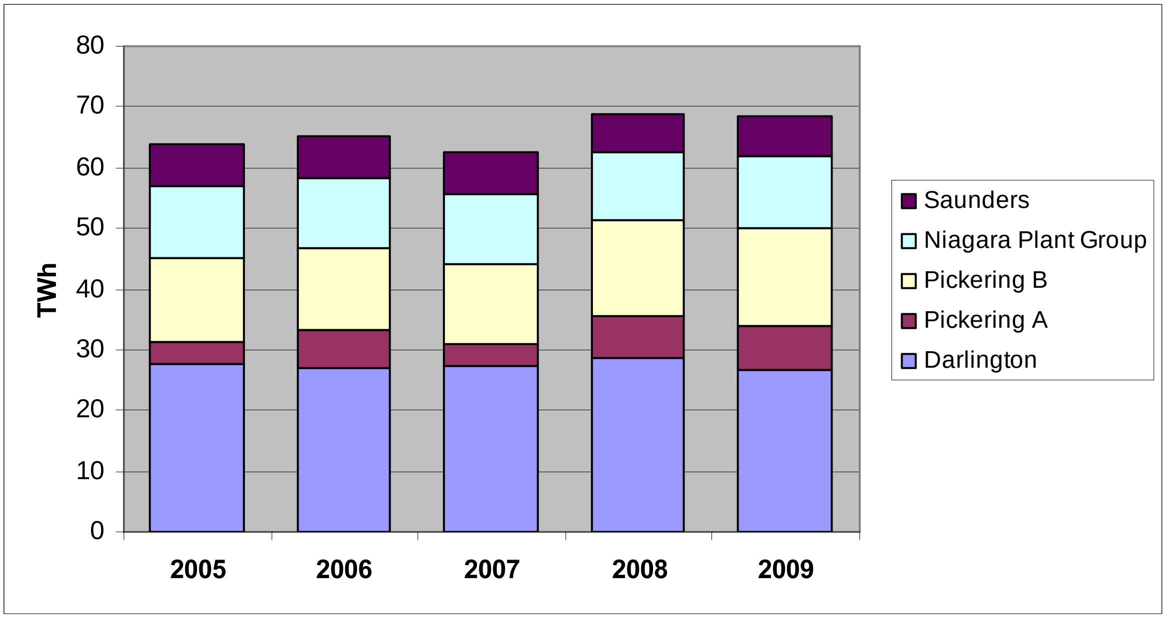
The prescribed hydroelectric generation facilities are owned directly by OPG and are not held in a subsidiary or other separate legal entity. The nuclear stations are held in wholly-owned subsidiaries of OPG. The prescribed facilities essentially are operated as two divisions of OPG – Regulated Hydroelectric and Regulated Nuclear.

From the opening of the Ontario wholesale power market on May 1, 2002 until March 31, 2005, the price charged by OPG for output from these plants was not subject to regulation by either the government of Ontario or the Board. OPG sold output from these plants into the hourly market operated by the Independent Electricity System Operator (IESO) and received the market price. The company was obligated, however, to make rebates to consumers pursuant to a Market Power Mitigation Agreement (MPMA), which had the effect of constraining OPG's total revenues.

Effective April 1, 2005, the government of Ontario eliminated the MPMA rebate mechanism. Amendments to the *OEB Act* gave the government the authority to set prices for output from the prescribed facilities. The payment amounts were set at $33.00 per mega-watt hour (MWh) for hydroelectric production up to 1900 MWh per hour, with market pricing for hydroelectric production greater than 1,900 MWh in any hour. The payment for nuclear output was set at $49.50 per MWh. OPG continues to offer the output of these plants into the IESO market but the amounts paid monthly to OPG by the IESO are based on the regulated payment amounts, not hourly spot market prices.

The prescribed facilities generate a significant portion of Ontario's electrical energy. Production for the past three years and forecast production for 2008 and 2009 are shown in Chart 1-1. (The Niagara Plant Group is comprised of the Beck and DeCew Falls plants.) In 2007, the nine stations generated 62.4 terra-watt hours (TWh) of electrical energy, or over 40% of the electrical energy used by Ontario consumers.

Chart 1-1: Actual and Forecast Energy Production



Sources: Ex. E1-1-2, Table 1; Ex. E2-1-1, Tables 2a and 2b.

OPG is subject to the terms of a Memorandum of Agreement (MOA), dated August 17, 2005, with the Province that sets out the Province's expectations regarding OPG's mandate, governance, performance, and communications. Key aspects of the MOA include:

- OPG has a commercial mandate, and is to operate on a financially sustainable basis and maintain the value of its assets for its shareholder.
- OPG's key nuclear objective is to reduce the risk exposure to the Province arising from its investment in nuclear generating stations.
- OPG is to seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU reactors worldwide as well as against the top quartile of private and publicly-owned nuclear generators in North America.

The MOA is attached as Appendix F to this decision.

1.2 OPG's Application

Section 78.1 of the *OEB Act* requires that the payment amounts set by the regulation stay in effect until the later of (i) March 31, 2008, and (ii) the effective date of the Board's first order.

In its application, which was filed November 30, 2007, OPG requested that the Board set new payment amounts based on a 21-month test period from April 1, 2008 to December 31, 2009. The new payment amounts proposed by OPG are based on a forecast cost-of-service methodology. OPG also sought an interim order from the Board for increased payment amounts effective April 1, 2008.

In February 2008, the Board held a hearing on OPG's request for an interim order. The Board did not grant OPG's request for increased payments on an interim basis but it did order that the current payment amounts be made interim as at April 1, 2008. Given the provisions of Section 78.1 of the *OEB Act* and the related regulation O. Reg. 53/05, a direct result of the Board's decision to make the current payment amounts interim was that the effective date of the Board's first order under Section 78.1 would be April 1, 2008.[1] Although that decision set the effective date as April 1, 2008, it was not necessary at that time for the Board to determine whether the new payment amounts would be the same as, or different from, the existing payment amounts. The issue of the implementation for new payment amounts remained outstanding and is addressed in Chapter 10.

OPG's proposed revenue requirement and revenue deficiency are summarized in Table 1-2. OPG's proposed revenue requirement is approximately $6.4 billion for the 21-month test period. If the current payment amounts were to stay in place until December 31, 2009, OPG estimated that the prescribed facilities would generate $5.4 billion of revenue for the 21-month period, about $1 billion less than OPG claims it requires. OPG has asked for increases in the payment amounts for the prescribed facilities to offset a large part, but not all, of that revenue deficiency. The company proposed a mitigation measure that would reduce the deficiency by $228 million, and asked for new payment amounts that would cover the remaining estimated deficiency of $798 million.

[1] The Board's oral decision is at pages 111 to 118 of the transcript, "EB-2007-0905, Motion for Interim Order, February 7, 2008" and is reproduced in Appendix C.

Table 1-2: OPG's Proposed Revenue Requirement

$ millions	Hydroelectric			Nuclear			Test Period Total
	2008	2009	Test period	2008	2009	Test period	
	9 months	12 months	21 months	9 months	12 months	21 months	
Expenses							
OM&A	$ 93.1	$ 119.0	**$ 212.0**	$ 1,587.7	$ 2,078.7	**$ 3,666.4**	**$ 3,878.4**
Gross revenue charge/nuclear fuel	179.9	244.1	**423.9**	125.7	204.2	**329.9**	**753.8**
Depreciation and amortization	47.1	63.2	**110.3**	221.5	316.4	**537.9**	**648.2**
New nuclear build/refurbishment	-	-	**-**	75.0	90.0	**165.0**	**165.0**
Property and capital taxes	6.5	8.7	**15.2**	16.3	22.0	**38.4**	**53.6**
Income taxes	-	-	**-**	-	-	**-**	**-**
Cost of Capital							
Short-term debt	5.8	6.0	**11.8**	5.2	5.4	**10.6**	**22.4**
Long-term debt	65.4	91.5	**156.9**	59.2	82.4	**141.5**	**298.4**
Return on equity	175.7	233.6	**409.3**	158.9	210.3	**369.2**	**778.5**
Other Revenue							
Ancillary and other	(24.3)	(33.1)	**(57.4)**	(49.4)	(50.9)	**(100.3)**	**(157.7)**
Bruce NGS (net)	-	-	**-**	(51.8)	(82.6)	**(134.3)**	**(134.3)**
Deferral, variance account recovery	(1.2)	(1.6)	**(2.8)**	55.7	72.5	**128.2**	**125.4**
Revenue Requirement	**548.0**	**731.4**	**1,279.3**	**2,204.1**	**2,948.4**	**5,152.5**	**6,431.8**
Forecast Revenue Based on Current Payment Amounts	427.1	611.1	**1,038.2**	1,897.7	2,470.2	**4,367.9**	**5,406.1**
Revenue Deficiency	120.9	120.3	**241.1**	306.4	478.2	**784.6**	**1,025.7**
Mitigation			**(90.1)**			**(137.9)**	**(228.0)**
Revenue Deficiency, net of mitigation			**$ 151.0**			**$ 646.7**	**$ 797.7**

Sources: Ex. A1-3-1, Tables 1 and 2; Ex. J1-2-1, Tables 2 and 3; Ex. F2-2-2, Table 1; Ex. K1-1-1, Table 3; Ex. K1-2-1, Table 1; Ex. K1-3-1, Table 1.

The principal reasons cited by OPG for the significant revenue deficiency are:

- **Capital structure/return on equity** – OPG proposed a deemed capital structure of 42.5% debt and 57.5% equity (current payment amounts are based on a capital structure of 55% debt and 45% equity). OPG also requested an increase in the return on equity to 10.5% from the 5% that was used to set current payment amounts. This issue is addressed in Chapter 8.
- **Rate base** – A higher rate base due largely to an increase at the end of 2006 in nuclear waste management and decommissioning liabilities. This issue is addressed in Chapter 5.

- **Operating expenses** – Increased operations, maintenance and administrative (OM&A) expense for the nuclear facilities, increased nuclear fuel expense, and the inclusion of interest expense on other post-employment benefit obligations, which was not included when the current payment amounts were set. This issue is addressed in Chapter 2.

Table 1-3 sets out the payment amounts proposed by OPG compared to current amounts. (Per MWh amounts and percentage increases in Table 1-3 are calculated assuming the new payments went into effect on April 1, 2008.)

Table 1-3: Proposed Payment Amounts

($ per MWh except fixed payment)	**Hydroelectric**	**Nuclear**
Current	**$33.00**	**$49.50**
Proposed		
Fixed payment	-	$1,221.6 million
Variable	$37.90	$41.50
Deferral account rate rider	-	$1.45
Net effective rate	**$37.90**	**$56.85**
% increase	**14.8%**	**14.9%**

OPG estimated that the proposed new payment amounts would increase the commodity portion of the bill by 5.1% for a typical Ontario electricity customer consuming 1,000 kWh per month.

The company proposed that it continue to charge only a per MWh amount for output from the hydroelectric facilities. OPG proposed a change to the incentive mechanism under which it receives market prices for some of the output from the hydroelectric plants. This issue is addressed in Chapter 3.

OPG proposed a new payment structure for the nuclear facilities, which would provide OPG with $1.2 billion over the test period (payable in equal monthly instalments) irrespective of the amount of energy produced by the nuclear plants. As a result of this fixed payment, the variable charge for nuclear output would decline from $49.50 to $41.50 per MWh, or to $42.95 per MWh if the nuclear deferral account rate rider is included. Under the current 100% variable payment structure, OPG would need to charge $56.85 per MWh ("net effective rate" in Table 3) to collect its proposed nuclear revenue requirement. This issue is addressed in Chapter 9.

The complete list of approvals sought by OPG is contained in Appendix B.

1.3 Legislative Requirements and Scope of Board Review

This is the first time the Board has set prices for an electricity generator. The Board has considerable experience in setting rates for electricity and natural gas distributors and transmitters that are, in substance if not legally, monopoly providers of energy delivery services. The electricity generation business in Ontario, however, is very different from distribution and transmission of electricity and gas. For example, there is no "market" for distribution of electricity to homes and businesses but there is a market in the electricity commodity that is produced by OPG and other generators. And, unlike the electricity and natural gas distributors that are subject to rate regulation, generators do not have an "obligation to serve."

Given that this is a new activity for the Board, and in light of the differences between the electricity generation and energy delivery businesses, the Board determined that it needed to carefully consider the appropriate regulatory methodology before OPG filed an application. In 2006, the Board consulted with consumer groups, electricity retailers, generators (including OPG), and other stakeholders on a variety of possible regulatory approaches. In the end, the Board determined that it would use a cost-of-service methodology to set the initial payment amounts for the prescribed generation facilities.[2] It left open the possibility of using an incentive regulation mechanism for subsequent payment orders.

Section 78.1(1) of the *OEB Act* establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1(4) states: "The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment."

[2] EB-2006-0064, Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.,* November 30, 2006.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* [3] (O. Reg. 53/05) provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed rules that govern the determination of some components of the payment amounts.

O. Reg. 53/05 affects the setting of payment amounts in three significant ways:

- It requires OPG to establish certain deferral and variance accounts and requires the Board to ensure recovery of the balances, subject to conditions in some cases;
- It requires the Board to ensure OPG recovers costs incurred and firm financial commitments related to certain activities. This requirement extends to costs and revenues of activities that are not related to the ongoing operation and maintenance of the prescribed facilities.
- It requires the Board to accept, in making its first order under section 78.1, certain financial values as set out in OPG's audited financial statements.

Each of these items is discussed below.

1.3.1 Transitional deferral and variance accounts

The initial version of O. Reg. 53/05, which was released in February 2005, required OPG to establish five variance accounts and one deferral account for the period up to the date of the Board's first order. Two additional transitional deferral accounts were added through amendments to the regulation in 2007 and 2008. The transitional accounts are listed in Table 1-4.

According to OPG, the total balance of all transitional variance and deferral accounts as at December 31, 2007, including some accounts that are not explicitly authorized by O. Reg. 53/05, is $339.3 million. These accounts are discussed in Chapter 7 of this decision.

[3] O. Reg. 53/05, *Payments Under Section 78.1 of the Act*, made February 16, 2005 and amended June 6, 2005, February 7, 2007, and February 13, 2008. O. Reg. 53/05 is reproduced in Appendix E.

O. Reg. 53/05 constrains the scope of the Board's review of the transitional variance and deferral account balances. For all accounts, the regulation sets the rate to be used to record interest on the balances, specifies the maximum recovery periods, and requires that the balances be recovered on a straight-line basis. For some accounts the regulation provides the Board with discretion to evaluate the prudence of the costs. In other cases, the Board is required to accept the account balances as set out in OPG's December 31, 2007 audited financial statements.

Table 1-4: Transitional Variance and Deferral Accounts per Regulation 53/05

Account	Reg. 53/05 Reference	OEB Discretion to Evaluate Prudence?
Differences in hydroelectric electricity production due to differences between forecast and actual water conditions	5(1)(a)	Yes
Unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities	5(1)(b)	Yes
Changes in revenues for ancillary services	5(1)(c)	Yes
Acts of God, including severe weather events	5(1)(d)	Yes
Transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules	5(1)(e)	Yes
Non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station[4]	5(4)	No
The revenue requirement impact of any change in OPG's nuclear liabilities resulting from a reference plan approved after April 1, 2008[5]	5.1	No
Costs incurred on or after June 13, 2006 in the course of planning and preparation for new nuclear facilities[6]	5.3	Yes

The only significant interpretation issues in respect of transitional accounts related to the Section 5.1 account, the revenue requirement impact of a change in nuclear

[4] In February 2007, the regulation was amended to allow OPG to include in this account costs related to Units 2 and 3 at Pickering A, which OPG's board of directors had determined would not return to service.

[5] Effective December 31, 2006, OPG recorded a significant increase in its nuclear decommissioning and waste management liabilities pursuant to a new approved reference plan under the Ontario Nuclear Funds Agreement. In February 2007, O. Reg. 53/05 was amended to require OPG to establish a transitional nuclear liability deferral account to record the revenue requirement impact of this change.

[6] The transitional nuclear development deferral account was authorized pursuant to a February 2008 amendment to Regulation 53/05.

liabilities. The issues were how the “revenue requirement impact” should be determined and whether the regulation permits OPG to include in the account costs arising from a change in the nuclear liabilities related to the Bruce nuclear generating stations. That issue is addressed in Chapters 5 and 6 of this decision.

1.3.2 Continuing deferral and variance accounts

The regulation requires that OPG establish three variance or deferral accounts to capture certain costs incurred on and after the effective date of the Board’s first order. The three required accounts are:

- Section 5(4) – Pickering A return to service deferral account (continuation of transitional account);
- Section 5.2 – Nuclear liability deferral account to capture the revenue requirement impact of changes in OPG’s nuclear liabilities arising from new approved reference plans; and
- Section 5.4 – Nuclear development variance account to capture differences between (a) actual non-capital costs incurred by OPG in the development of proposed new nuclear facilities, and (b) the amount of any such non-capital costs included in the payments set by the Board.

As with the transitional deferral and variance accounts, O. Reg. 53/05 specifies the method and maximum period of recovery. The interest rate on the accounts is to be set by the Board.

In addition to these accounts, OPG has requested Board approval for several other deferral and variance accounts, as discussed in Chapter 7 of this decision.

1.3.3 Assured recovery of certain costs and firm financial commitments

In addition to the requirements related to recovery of variance and deferral accounts, O. Reg. 53/05 also directs the Board to ensure OPG recovers certain other costs. The relevant sections of the regulation are reproduced below.

6(2)4 – Costs to increase output from or to refurbish prescribed facilities
The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

i.if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

ii.if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

6(2)4.1 – New nuclear development
The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

6(2)8 – Revenue requirement impact of nuclear decommissioning liability
The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

6(2)9 – OPG's costs related to the Bruce nuclear generating stations
The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

6(2)10 – Bruce Revenues in Excess of Costs
If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2 [Pickering A, Pickering B, Darlington].

Two of the categories listed above (new nuclear development, and the revenues and costs of the Bruce nuclear stations) are for costs that are not related to the prescribed facilities. Thus, O. Reg. 53/05 requires the Board to take into account costs and revenues of unregulated activities when setting payment amounts for regulated activities.

Issues that arose in the hearing on these sections of the regulation included: the method to be used to determine the "revenue requirement impact" of nuclear decommissioning and waste management liabilities (Chapter 5); the method of determining OPG's revenues and costs related to the Bruce nuclear stations (Chapter 6); and, whether Section 6(2)4 permits OPG to recover non-capital costs incurred before April 1, 2008 (Chapter 7).

1.3.4 Acceptance of certain values in OPG's 2007 financial statements

O. Reg. 53/05 requires that, in making its first order, the Board accept certain financial values set out in OPG's audited financial statements. Sections 6(2)5 and 6(2)6 of the regulation state:

> 5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
>
> i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
>
> ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
>
> iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
>
> 6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
>
> i. capital cost allowances,
>
> ii. the revenue requirement impact of accounting and tax policy decisions, and
>
> iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

The most recent audited financial statements approved by OPG's Board of Directors are as at and for the year ended December 31, 2007.

OPG identified the amounts in the 2007 audited financial statements that it believes the Board must accept. A summary of OPG's submission is shown in Table 1-5.

Table 1-5: OPG's Position on Financial Statement Amounts That the Board Must Accept

Description	Amount *($ millions)*	Impact on Payment Amounts
Assets		
Fuel Inventory	$231	Opening rate base
Materials and supplies	420	Opening rate base
Fixed assets in service	7,901	Opening rate base; depreciation expense for prescribed facilities and Bruce
Construction work in progress	509	Addition to rate base during test period
Net regulatory assets	356	Deferral/variance account recovery
Liabilities		
Long-term debt	4,065	Deemed interest expense in test period
Deferred revenue	132	Bruce NGS revenue during test period
Regulatory liabilities	14	Deferral/variance account recovery

Source: Exhibit 2.7.

Under OPG's interpretation of these sections of O. Reg. 53/05, the Board has very little discretion in determining the amount of OPG's rate base. The rate base proposed by OPG is based mainly on amounts that OPG submits the Board must accept (fixed assets, inventory, material and supplies at December 31, 2007), and a significant portion of additions to rate base during the test period are made up of costs that are classified as construction work in progress in the 2007 financial statements.

The following chapters in this decision cover the major issues addressed in this proceeding – nuclear and hydroelectric OM&A and capital expenditures, nuclear waste management and decommissioning liabilities, revenues and costs related to OPG's lease of the Bruce nuclear generating stations, deferral and variance accounts, cost of capital, and the design of the payment amounts. As is evident in these chapters, O. Reg. 53/05's requirements on deferral accounts, assured cost recovery, and acceptance of financial statement amounts were relevant to the Board's deliberation and findings on most of the major issues in this case.

1.4 General Approach to Statutory Interpretation

As stated previously in this chapter, Section 78.1(1) of the *OEB Act* establishes the Board's authority to set the payment amounts for the prescribed generation facilities, and Section 78.1 (4) requires, among other things, that the Board shall make an order under that section in accordance with the rules prescribed by the regulations. O. Reg. 53/05 includes detailed rules that govern the determination of some components of the payment amounts.

When interpreting Section 78.1 and O. Reg. 53/05, the Board applied the modern principle of statutory interpretation cited and adopted by the Supreme Court of Canada,[7] and referred to by Board staff in its legal submissions:

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context, in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament.[8] (the "modern principle")

Board staff's legal submissions concerning the principles of statutory interpretation and the relevant statutory framework were not challenged by any party, and were accepted and relied upon by the Board.

In addition, the Board relied upon *Monsanto Canada Inc*. v. *Superintendent of Financial Services* and *Biolyse Pharma Corporation* v. *Bristol-Myers Squibb*, in which the Supreme Court of Canada discussed and applied the modern principle to the interpretation of regulations.

[7] The Supreme Court of Canada has cited the modern principle in such cases as *Monsanto Canada Inc*. v. *Superintendent of Financial Services* [2004] 3 S.C.R. 152 and *Biolyse Pharma Corporation* v. *Bristol-Myers Squibb* [2005] 1 S.C.R. 533.

[8] Board Staff Submissions, p. 3. citing Ruth Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed.), Butterworths (Toronto), 2002, p.1.

1.5 Summary of Board Findings

The Board has reduced OPG's requested revenue requirement in a number of areas. The following list summarizes those adjustments; the details of the findings are contained in the subsequent chapters of this decision:

- A reduction in Base OM&A for the Pickering A nuclear station
- A reduction in nuclear advertising expense
- An increase in the revenue attributable to various activities in the hydroelectric business (segregated mode operation and water transactions)
- A reduction in the revenue requirement related to the nuclear waste management and decommissioning liabilities
- A reduction in the deemed equity ratio from the proposed level
- A reduction in the return on equity to 8.65% from the proposed level of 10.5%
- An increase in the revenue attributable to the Bruce nuclear station
- An increase in the revenue requirement due to adjustments to the balances in various deferral and variance accounts and an adjustment to the proposed recovery period for one account
- A reduction in the level of mitigation to be provided by OPG

OPG applied for a total revenue requirement of $6,203.8 million for the 21 month period. The Board does not yet have all of the data necessary to establish the final revenue requirement. Based on the data the Board does have, the Board estimates that the revenue requirement will be approximately $6,017 million for the 21 month period. The Board further estimates that the resulting impact will be an approximate 8.5% increase in the per MWh payment amounts.

2 NUCLEAR FACILITIES

OPG operates by far the largest nuclear fleet in Canada and one of the largest in North America. OPG's prescribed nuclear facilities – Pickering A, Pickering B and Darlington – have a combined generating capacity of 6,606 MW, or twice the capacity of the company's prescribed hydroelectric facilities.

This chapter deals with issues related to the prescribed nuclear facilities –the nuclear production forecast, operating, maintenance and administration expenses (OM&A), capital expenditures, fuel costs, and other revenue. This chapter also addresses costs related to new nuclear facilities and the possible refurbishment of existing nuclear units.

2.1 Production Forecast

Forecast nuclear production is 51.4 TWh for 2008 and 49.9 TWh for 2009. For the 21-month test period, forecast production is 88.2 TWh. Actual and forecast production for the prescribed nuclear facilities are set out in Table 2-1.

Table 2-1: Nuclear Production (TWh)

	2005	2006	2007	2008 Forecast	2009 Forecast
Nuclear stations:					
Darlington	27.6	27.0	27.2	28.6	26.6
Pickering A	3.6	6.4	3.6	7.1	7.3
Pickering B	13.9	13.5	13.4	15.7	16.0
Total - Nuclear stations	**45.1**	**46.9**	**44.2**	**51.4**	**49.9**
Unit capacity factor (%)	83.8	81.5	77.1	88.7	86.2
Planned outages (days)	345.8	323.5	331.2	254.1	343.4
Forced extensions of planned outages (days)	39.8	167.0	131.2	-	-
Forced loss rate (%)	5.4	6.4	11.7	5.1	4.2

Source: Ex. E2-1-1, Table 1

OPG's forecast of nuclear production starts with the assumption that all units run every hour of the year at a 100% capacity factor. From that full capacity output of approximately 58 TWh, OPG deducts production that will not occur due to planned outages and an estimate of forced production outages. OPG also deducts a fleet uncertainty adjustment, typically 0.5 TWh (around 1% of forecast production), to bring the fleet level production to within acceptable confidence limits.

OPG is not seeking a variance account for deviations between actual production and forecast. Accordingly, any variance of the forecast from actual production will be OPG's risk.

None of the intervenors objected to OPG's forecast although Energy Probe Research Foundation (Energy Probe) argued that, given OPG's past performance, the Board should be skeptical of the production forecasts and the estimated forced loss rates (FLR). OPG responded that history does not necessarily repeat itself and that OPG has taken measures to improve its production performance. OPG further claimed that while the production target is challenging, this forecast will incent the organization to achieve maximum generation while ensuring safe and reliable operation.

OPG also questioned submissions by Board staff that the fleet level uncertainty adjustment factor does not reflect historical performance. OPG replied that unplanned outages are properly captured by the FLR, not the fleet level uncertainty adjustment.

Board Findings

Except for forecast production for the Pickering A station, OPG's forecast nuclear production is line with its past experience. Darlington production is expected to fall off slightly in 2009 due to a required four-unit outage for vacuum building inspection.

OPG is forecasting substantially higher production from the two Pickering A units than occurred during 2005 to 2007. OPG expressed confidence in its ability to achieve a higher capacity factor at Pickering A. The Board notes that OPG will be at risk if actual production is less than forecast.

The Board accepts the OPG forecast of nuclear production of 88.2 TWh and directs that OPG use that amount to derive the nuclear payment amount for the test period.

2.2 Operating, Maintenance and Administration Costs

OPG forecast total OM&A costs of $2,184.6 million for 2008 and $2,168.7 million for 2009. Table 2-2 shows the components of actual and forecast nuclear OM&A. Those amounts include forecast OM&A costs of $100 million in 2008 and $90 million in 2009 related to preparatory work on new nuclear facilities and the possible refurbishment of existing units. Those costs, which are subject to specific provisions in O. Reg. 53/05, are not related to the operations of the prescribed facilities. The new generation development and refurbishment OM&A costs are shown separately in Table 2-2 and are addressed in section 2.6 of this decision.

Table 2-2: Total OM&A Expenses

$ millions	2005 [9]	2006	2007	2008 Forecast	2009 Forecast	CAGR 2005-2009
Base OM&A (see Table 2-3)	$1,035.1	$1,122.3	$1,181.6	$1,260.8	$1,278.0	5.4%
Project OM&A	155.9	142.0	111.6	144.6	137.1	-3.2%
Outage OM&A	163.0	187.7	215.6	192.2	207.9	6.3%
Allocation of corporate costs [10]	356.2	423.2	446.8	457.0	430.2	4.8%
Asset service fee	14.7	30.8	33.2	29.9	25.5	14.8%
Total OM&A (before new generation development)	**$1,724.9**	**$1,906.0**	**$1,988.8**	**$2,084.5**	**$2,078.7**	**4.8%**
New generation development/ refurbishment	1.3	11.5	35.0	100.0	90.0	
Total OM&A	**$1,726.5**	**$1,917.5**	**$2,023.8**	**$2,184.5**	**$2,168.7**	**5.9%**

Sources: Ex. F2-1-1, Table 1; F2-2-1, Table 1.

Base OM&A, which accounts for 60% of total OM&A, includes costs incurred at the three nuclear stations as well as the costs of common nuclear support divisions, nuclear services, and waste and transportation services.

[9] 2005 total excludes impairment charges and write-offs related to Pickering A, Unit 2.

[10] The allocation of corporate costs is addressed in Chapter 4 of this decision.

The components of actual and forecast Base OM&A are set out in Table 2-3 below. Over the period 2005 to 2009, the Base OM&A expenses for Darlington increase at an average annual compound rate of 6.7%, compared to 3.9% for Pickering A and 2.8% for Pickering B.

Table 2-3: Base OM&A (excluding new generation development and refurbishment)

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast	CAGR 2005-2009
Nuclear stations:						
Darlington	$ 243.1	$ 278.6	$ 294.6	$ 311.2	$ 314.9	6.7%
Pickering A	172.9	169.5	177.1	197.7	201.3	3.9%
Pickering B	246.9	263.2	272.7	278.6	275.7	2.8%
Total - Nuclear stations	662.8	711.3	744.5	787.5	791.9	4.5%
Nuclear support divisions	341.2	371.0	393.2	414.0	424.0	5.6%
Nuclear services[11]	26.9	35.5	39.1	54.1	56.6	20.4%
Waste and transportation services	4.2	4.5	4.8	5.3	5.6	7.5%
Total Base OM&A	**$ 1,035.1**	**$ 1,122.3**	**$ 1,181.6**	**$ 1,260.9**	**$1,278.0**	**5.4%**

Source: Ex F2-2-1, Table 1

Forecast Project OM&A costs include $5.1 million for the possible Pickering B Refurbishment (which is addressed in section 2.6 of this decision), $40.6 million for work to isolate Pickering A units 2 and 3 (P2/P3 isolation project), $58.4 million for Infrastructure, and $52.2 million for listed work awaiting release approval. The P2/P3 isolation project involves moving, isolating or repositioning safety or control systems that are required for the continued operation of Pickering A units 1 and 4 after the safe storage of Pickering A units 2 and 3.

Outage OM&A represents incremental costs necessary to complete planned outages, including forced extensions of planned outages. They include costs for overtime, non-regular labour, augmented services, materials, other purchased services and the costs of Inspection and Maintenance Services.

The Asset Service Fee is Nuclear's share of the costs of the fixed assets that are centrally held by OPG, but that are used to provide services for the regulated nuclear

[11] The nuclear services category includes indirect costs of staff working on refurbishment programs.

and hydroelectric businesses. These fixed assets include OPG's head office, the Kipling Building complex, and OPG-wide IT systems and applications.

The Corporate Costs component of OM&A, with the exception of the nuclear advertising element, is addressed in Chapter 4 of this decision.
Board staff and several intervenors questioned the amount of forecast OM&A costs on three grounds. These were (i) the substantial increase in costs between 2005 and 2009; (ii) the increase in labour costs; and (iii) the poor benchmarking of productivity performance. Each is considered in turn.

Increases in total OM&A, 2005 to 2009
For the period 2005 to 2009, the increase in total OM&A costs is forecast to be $442.5 million, a growth of 6.4% per year based on simple average (or 5.9% per year on a compound basis as indicated in Table 2-2).

The School Energy Coalition (SEC) submitted that the annual escalation over the 2005 to 2009 period should be limited to 3% per year which would reduce the proposed OM&A budgets by $284 million in 2008 and $217 million in 2009. CME proposed the total increase be restricted to 6% above 2007 OM&A costs, the rationale being the recent OEB-approved incentive rate adjustments of less than 2% per year for Enbridge Gas Distribution and Union Gas.

OPG responded that using 2007 as a base year ignored the significant cost impact of spending on nuclear generation development during the test period ($100 million in 2008 and $90 million 2009 as shown in Table 2-2). OPG submitted that the arguments of SEC and CME failed to recognize the unique cost drivers during the period. These included safety requirements of the Canadian Nuclear Safety Commission and vacuum building outage preparation at both Darlington and Pickering, as well as new reliability improvement initiatives at Pickering.

OPG also pointed out that of the $331.6 million increase in Base OM&A between 2005 and 2009, $165 million was due to labour escalation and of the remaining $166 million, $88 million was for new generation development. Approximately $39 million was for security and other improvements in nuclear training. OPG noted that labour costs constitute 74% of OPG's nuclear Base OM&A costs and that 90% of OPG's employees are covered by collective agreements.

OPG argued that the intervenors are in substance attempting to place OPG under a formulaic or incentive rate-making program. OPG noted that the Board rejected this concept in its *Filing Guidelines for Ontario Power Generation*,[12] which indicated that the Board will implement an incentive regulation formula when it is satisfied that the base payment amounts provide a robust starting point for that formula. OPG further argued that it was important to examine the cost drivers that underlie OM&A increases as opposed to simply discounting the average increase of 6% a year to 3% a year or establishing a formulaic 6% increase over the entire period.

OPG claimed that the funding levels proposed by the intervenors will deny OPG the funds necessary to reduce maintenance backlogs, improve preventative maintenance, and outage planning. It would also compromise OPG's ability to comply with the Province's directions regarding refurbishment and new nuclear build. OPG stated that almost $189 million of the Base OM&A increase from 2005 to the 2009 period was due to nuclear new build and Pickering B refurbishment. Both were undertaken at the direction of the Province.

Increased labour costs

Intervenors also expressed concern about the increase in labour costs over the period 2005 to 2009. SEC pointed out that labour costs, as demonstrated in reports prepared by Mercer Human Resources Consulting (Mercer) and Towers Perrin, are well above market levels. SEC also questioned the rationale for a license retention bonus that is paid to nuclear operators, and the richness of other post employment benefits (OPEBs).

The Vulnerable Energy Consumers Coalition (VECC) argued that as the 6.5% increase in compensation from 2007 to 2008 per nuclear FTE (excluding OPEB costs) was not satisfactorily explained by OPG, the increase should be limited to 4%, which would reduce total 2008 compensation costs by $20.6 million.

Both the Association of Major Power Consumers in Ontario (AMPCO) and SEC questioned the OPG Incentive Pay Program given OPG's poor economic performance. They noted that performance payouts increased from $24.6 million in 2005 to $29 million in 2007 while nuclear production productivity declined and operating costs per unit increased by 19%. AMPCO recommended that OPG introduce a more meaningful incentive pay plan at its next rates case. OPG responded that these arguments rely on

[12] Ontario Energy Board, *Filing Guidelines for Ontario Power Generation: Setting Payment Amounts for Prescribed Generation Assets*, EB-2006-0064, July 27, 2007.

a selective use of evidence and demonstrate a lack of understanding of its Incentive Pay Program; that its staffing levels increased due to initiatives by nuclear regulators and changing demographics; and that any labour costs must consider annual wage scale movements.

OPG stated that any organization with a heavily unionized workforce must balance its business requirements with the long-term interest in working with a union. OPG submitted that the Board's review of OPG's management decisions regarding labour negotiations must consider the consequences of potential labour disruptions.

The Power Workers Union (PWU) supported OPG's proposed OM&A expenditures as costs necessary for the reliable and safe operation of OPG's prescribed nuclear assets. PWU submitted that any analysis of labour cost trends should exclude components that are subject to significant variance such as pension and OPEB costs. PWU argued that the average annual increase of 4% is reasonable and consistent with the 3% to 4% increase in OPG's standard labour rate. PWU further submitted that the labour costs of Bruce Power L.P., the operator of the Bruce nuclear stations, are the proper comparator for OPG's labour costs. PWU submitted that such a comparison revealed OPG's 2006 wages (for PWU staff) were, on average, 12.8% lower than Bruce Power's costs.

Productivity and benchmarking

The third area of concern raised by many intervenors was OPG's benchmarked performance.

A number of benchmarking analyses and cost studies were examined in this proceeding. These included:

- the Electricity Utility Cost Group (EUCG) cost performance data base,
- the World Association of Nuclear Operators (WANO) database,
- the Navigant Staffing Benchmarking Analysis (Navigant Report), and
- salary surveys prepared by Towers Perrin, Mercer Human Resources Consulting, and Watson Wyatt.

EUCG is a voluntary association of nuclear generators, including most American nuclear generators, as well as non-North American ones. EUCG collects, validates and publishes cost and production data.

The WANO data base provides non-cost performance data, including a unit capability factor and nuclear index performance. The unit capability factor is a WANO standard while the nuclear performance index is a weighted average of ten WANO indicators.

The Navigant Report was commissioned by OPG in 2006. The primary objective of the study was to develop staffing benchmarks for OPG nuclear operations. Benchmarks were based on data from the four Canadian CANDU plants not operated by OPG (Bruce A, Bruce B, Pt. Lepreau in New Brunswick, and Gentilly-2 in Quebec).

Towers Perrin, Mercer and Watson Wyatt conduct yearly surveys of their clients to determine overall salary increases. OPG engaged Mercer to conduct a market benchmarking review comparing actual salary band compensation levels. OPG also participated in a study of the Power Services Industry conducted by Towers Perrin. The study compares salary levels by position where job matches are sufficiently close.

A number of parties referred to the MOA between the Province of Ontario and OPG which sets out the Province's expectations regarding benchmarking and operational performance:

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.[13]

SEC, AMPCO and the Canadian Manufacturers & Exporters (CME) noted that over the 2005 to 2007 period, OPG's productivity declined and production did not match, let alone exceed, the increase in costs. The intervenors questioned OPG's commitment to benchmarking.

Board Staff submitted benchmarking evidence indicating that OPG's operating costs substantially exceed others in the industry.

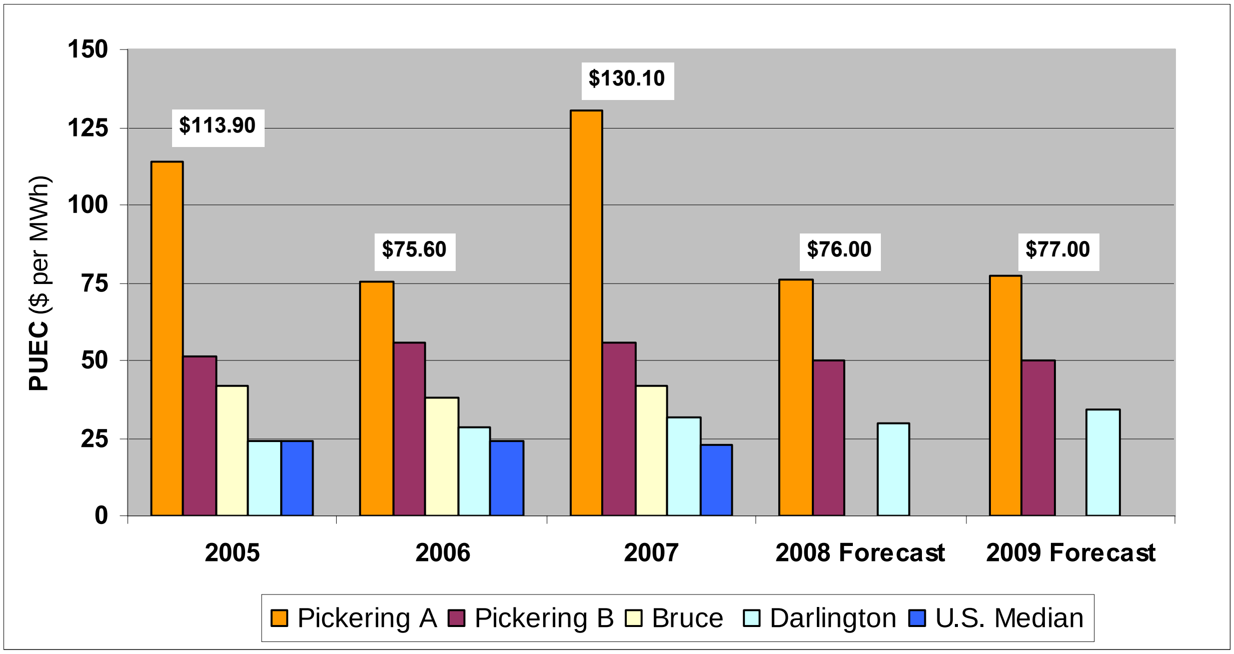
Chart 2-1 shows the differences in the production unit energy cost (PUEC) in the period from 2005 to 2007 along with OPG's forecasts for 2008 and 2009. PUEC is calculated by dividing a plant's OM&A and fuel costs by the amount of energy produced in a

[13] Memorandum of Agreement, paragraph A.3.

period. The per MWh amounts shown on the face of the chart are for the Pickering A station, which has the highest PUEC of the stations shown on the chart.

Chart 2-1 shows that the production cost per MWh for Pickering A and Pickering B have been substantially greater than for Bruce Power. Over the three years 2005 to 2007, Pickering A's unit production cost was on average three times higher than Bruce Power and four times the U.S. median. Darlington's performance is better than Bruce Power, but is worse than the U.S. median. The average cost per MWh at Pickering A over the three-year period was $107 compared to $24 for the U.S. median and $41 for Bruce Power.

Chart 2-1: Comparative Nuclear PUEC Costs



Sources: Ex. J5.4; Ex. L-4-2, Attachment 3, pp. 18, 21, and 24.

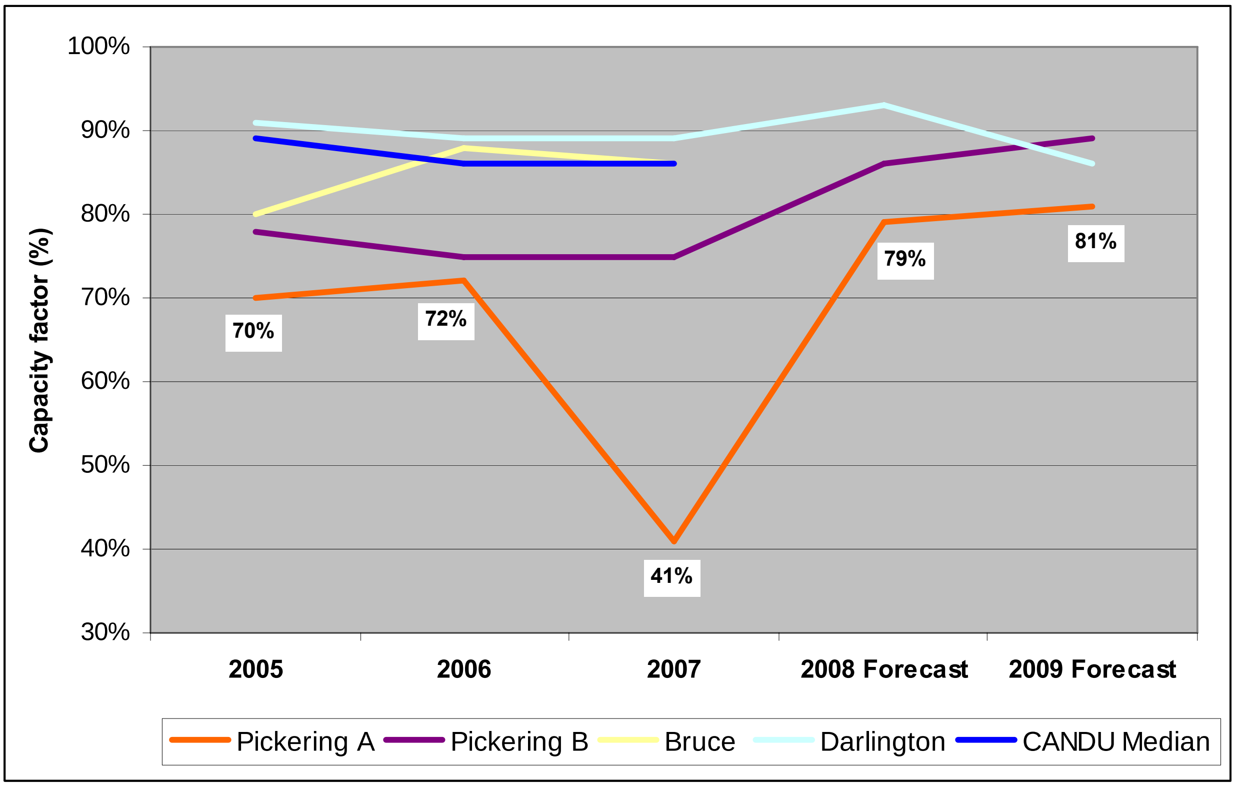
Many intervenors were critical of both the results of OPG's benchmarking and what they viewed as the apparent reluctance to engage in benchmarking. AMPCO submitted that Pickering A is almost five times more costly than the top quartile of U.S. operations, while Pickering B is two and a half times more costly.

The PUEC of a generating plant is a function of both the level of costs incurred and the plant's capacity factor. Even a very low-cost facility can have a high PUEC if the plant has an extended outage in a period.

Chart 2-2 shows the capacity factors for the OPG-operated plants compared to the capacity factors of Bruce Power and the Canadian CANDU median. The capacity factors shown on the face of the chart are for the Pickering A station, which had the lowest capacity factor of the plants included in the chart.

OPG stated that in the first quarter of 2008, the capacity factors achieved at its nuclear stations were: Darlington – 99%; Pickering A – 79%; and Pickering B – 86%.

Chart 2-2: OPG's Nuclear Capacity Factors Compared to Bruce and Canadian CANDU Median



Source: Ex. J5.4, Ex. L-4-2, Attachment 3

Darlington's performance over the three-year period 2005 to 2007 was similar to that of Bruce Power and the Canadian CANDU median; however, Pickering A and Pickering B operated at lower capacity factors, especially in 2007. Over the three-year period 2005 to 2007, the average capacity factor at Pickering A was 61% compared to 85% at Bruce Power and 87% for the CANDU median.

A number of parties questioned the long-term viability of the Pickering plants, particularly Pickering A. Energy Probe noted that the operating costs of Pickering A exceeded the value of the electricity generated and asked the Board to withhold payments for any facility that raises the cost of power for consumers.

AMPCO argued that over the 2005 to 2007 period, the average cost of Pickering A power was double the Hourly Ontario Energy Price and the nuclear payment amount received by OPG under O. Reg. 53/05. AMPCO concluded that even with the forecasted cost of 8.1 cent/kWh (AMPCO's calculation) in the test period, the prudence of continued operation of Pickering A remains a concern. AMPCO argued that OPG should be required to file a long-term assessment of the viability of Pickering A in the next rates application. SEC also argued that OPG should be directed to file a plan which demonstrates that Pickering A and Pickering B can operate at costs similar to other generators.

OPG responded that the Board's role in this application is to review the costs of Pickering A, and based on these costs, set reasonable payment amounts. OPG argued that the Board should not, and cannot, decide the ultimate viability of Pickering A, as this is beyond the scope of Section 78.1 of the *OEB Act*.

Regarding the AMPCO and SEC submissions that OPG's costs are excessive given the benchmarking results, OPG responded that the intervenors used selective data and disregarded technical differences regarding Pickering A and Pickering B. OPG also argued that AMPCO's assertion that OPG was resistant to benchmarking was unsupported. OPG maintained that it is committed to benchmarking and is in full compliance with the requirements in the MOA.

OPG also noted that it expects Pickering A and B's performance to improve substantially in the future and submitted that Darlington will continue to perform as well as it has in the past. Most of the intervenors countered that the forecasted results for 2008 and 2009 are unduly optimistic and the Board should discount these projections.

OPG also questioned the arguments by a number of intervenors that the Navigant Study supports the conclusion that 2006 staffing levels were 12% higher than benchmark. OPG claimed that the Navigant Study cannot be used to test the level and reasonableness of OPG's labour cost because the Navigant Study is not representative of staffing levels in the test period.

Regarding the suggestion that the OM&A budget should be treated on an envelope basis, OPG responded that while it should be free to manage specific expenditures within an OM&A envelope, it is opposed any determination of the OM&A costs through a benchmarking exercise.

Board Findings

This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. The second is the extent to which the Board should use the detailed benchmarking evidence to assess the reasonableness of the costs OPG seeks to recover.

With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts.

As discussed in Chapter 9 of this decision, the Board has rejected OPG's proposed payment structure for the nuclear plants (which was to include a fixed amount of $1.2 billion during the test period plus a per MWh payment amount to cover the balance of the revenue requirement). Instead, the Board has decided to retain the current variable payment structure of an amount per MWh regardless of the level of production. If OPG operates its plants at a unit cost higher than the approved payment amount, the excess costs will be borne by OPG and its shareholder. Consumers will not be at risk for costs in excess of the costs used to set the payment amount. Therefore, the Board does not accept the suggestion of intervenors that it order OPG to file a study on the long-term viability of Pickering. The long-term viability of the Pickering stations is an assessment more properly made by the shareholder knowing that the Board will only allow the recovery of reasonable costs and that the payment structure will be such that consumers will not bear production risk.

The benchmarking issue is more important. The direction given by the Province to OPG in the MOA is very specific. OPG is directed to seek "continuous improvement in its nuclear generation business." To this end, the MOA states: "OPG will benchmark its performance in these areas against CANDU Nuclear plants worldwide as well as against the top quarter of private and publicly owned nuclear electricity generators in North America." And finally, the MOA states: "OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board in this proceeding is faced with the task of determining whether the costs OPG seeks to recover are reasonable. A very important tool available to the Board is the benchmarking analysis.

Very little benchmarking evidence was filed by OPG in its initial application. This evidence was largely produced during cross-examination when OPG filed the Navigant Study.

The most common measure of productivity in nuclear generation industry is PUEC. The PUECs of the two Pickering stations are far above industry averages as Chart 2-1 indicates; in fact, the operating cost performance of Pickering A may be the worst of any nuclear station in North America. In 2006, Pickering A had a PUEC three times the U.S. average ($75.60 per MWh compared to $24.00 for the U.S. Median) and twice the Bruce unit cost of $38.00 per MWh; in 2007 Pickering A had increased to $130.00 per MWh compared to $23.00 for the U.S. median and $42.00 at Bruce.

Pickering B's 2006 PUEC was better at $55.00 per MWh but was still more than twice the U.S. median and significantly above Bruce. In 2007, Pickering B remained relatively constant at $56.00 per MWh, which was still more than twice the U.S. median and 30% greater than Bruce. The Darlington plant demonstrates a more respectable performance at $29.00 per MWh in 2006 and $32.00 per MWh in 2007.

The unit costs at Pickering A and Pickering B are forecast to improve in 2008 due to higher planned capacity factors. OPG claimed that the Pickering A operating costs will decline from $130.10 per MWh in 2007 to $76.00 in 2008 and $77.00 in 2009. Similarly, OPG claimed that the Pickering B costs will decline from $56.00 in 2007 to $50.00 in both 2008 and 2009. A number of intervenors were skeptical of these promised results.

OPG made two arguments concerning the PUEC benchmarking data. The first argument made by OPG was that the productivity results flow from technology decisions made in the past that should not be questioned using hindsight. In other words, the Board must assume that the technology decisions were prudent at the time they were made and the poor productivity results evident today, while unfortunate, are consequences of those decisions to be borne by the Ontario consumer. The Board finds this an unsatisfactory response.

OPG's primary argument was that the benchmarking data is unreliable.

The Board does not believe it is sufficient for OPG to simply discount the benchmarking studies on the basis of data quality. The studies are all based on standard measures used by the nuclear industry throughout the United States and Canada. While caution should be exercised when reviewing such data, the Board is satisfied that the studies provide meaningful insights into OPG's operations. Moreover, even if there are frailties in the data, the differentials remain striking, particularly with respect to Pickering A. The reason why the MOA emphasized benchmarking was because such studies can and do shine a light on inefficiencies and lack of productivity improvement.

While OPG criticizes the data, the Board notes that few steps have been taken to improve the quality of studies. The Board also notes that benchmarking studies were not filed as a matter of course but rather were reluctantly produced during the course of cross-examination.

Moreover, the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. The Navigant Study was delivered two years ago on September 15, 2006. There appear to be no benchmarking studies underway. And OPG has not decided what benchmarking evidence, if any, it will present at the next rates case.

Navigant completed Phase I of its study in 2006. Phase 2 as described at page 9 of the Navigant Report was to set OPG's strategy and performance targets. Specifically, Phase 2 was to address the question "what level of cost and operational performance improvement is justified". Phase 3 was to develop and execute an implementation plan. Specifically, Phase 3 was to address the questions "what specific initiatives and actions are needed to achieve identified performance improvement targets".

The questions Navigant suggested should be addressed in the second and third phases of the study are important questions. They are directly responsive to paragraph A.3 of the MOA.[14]

[14] "OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.

The production costs of the Pickering A station are a particular concern. In the past, a major reason for the high PUEC for Pickering A has been the extent of unplanned outages and the resulting low capacity utilization. OPG has forecast significantly higher capacity factors for Pickering A in 2008 and 2009. But, as Chart 2-1 illustrates, even at those higher production levels, the PUEC for Pickering will still remain well above the PUEC for Pickering B, will be significantly higher than the PUEC of the Darlington station, and will stay well above the PUEC achieved by the Bruce station over the period 2005 to 2007. Thus, poor capacity factors are not the whole reason for a high PUEC at Pickering A.

The Board estimated the PUEC for Pickering A assuming it were able to reach the forecast capacity factors of the Pickering B station in 2008 and 2009. Even if Pickering A were able to increase its planned capacity factors by that much (from 79% in 2008 and 81% in 2009 to 86% in both years), the Board estimates that the PUEC of Pickering A would only fall to around $70 per MWh, a level that is still much higher than the next highest cost station in Chart 2-1. In the Board's view, this indicates an issue with the overall level of production costs at Pickering A.

Under these circumstances, the Board believes that a reasonable action is to disallow 10% of the Base OM&A costs of Pickering A. This represents a test period disallowance of $14.9 million in 2008 and $20.1 million in 2009. Even with those amounts removed from the revenue requirement, the amount of the operating costs of Pickering A will still remain well above those of other nuclear plants.

The Board will have an opportunity to reexamine this issue when the benchmarking studies are updated in the next proceeding. At that time the Board will examine any improvement or deterioration in production unit energy costs compared to other utilities, and the reasons for those changes.

Aside from this adjustment, the Board will allow the OM&A forecast by OPG. The Board understands the concern of the intervenors regarding the level of costs, but believes it is important to examine underlying cost drivers. A number of the planned expenditures are related to safety and cost improvements. The Board's main concern is that there be a significant improvement in operating costs. As the MOA stated, "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." The Board recognizes that new investments will be necessary to reduce these costs.

2.3 Nuclear Advertising

OPG included in its revenue requirement for the test period $3 million for membership in the Canadian Nuclear Association (CNA). Of this amount, $2.3 million is for OPG's contribution to CNA's advertising program. OPG forecast an additional expenditure of $3.7 million on advertising in support of nuclear generation. In total, $6 million is forecast to be spend on advertising related to nuclear generation.

The OPG position was that this advertising is designed to create public support for nuclear generation and communicate to the public that nuclear generation is safe and environmentally friendly. SEC claimed this was not the purpose of the advertising. Rather SEC claimed it was an attempt to influence public opinion on the future of Ontario's supply mix. SEC asked the Board to disallow all the advertising expense.

Energy Probe also submitted that customers should not pay for nuclear advertising intended to influence public opinion or public policy. It cited numerous examples where U.S. regulators disallowed such expenditures and concluded that the entire nuclear advertising expenditure of $6.7 million should be disallowed.

OPG responded that its nuclear advertising activities have nothing to do with the future power supply but are designed to inform Ontario residents about nuclear safety and environmental benefits. OPG stated that Energy Probe's arguments were questionable characterizations of statements by OPG's witnesses and should not be treated as evidence. In addition, OPG noted that Energy Probe failed to acknowledge that some of the U.S. rules cited allowed for exemptions.

OPG also disputed that nuclear advertising can influence the outcome of the IPSP proceeding noting that the Province has already decided the future course for nuclear generation in Ontario. OPG claimed that a full discussion of nuclear energy, by both proponents and opponents, is in the public interest and OPG's communication is an essential part of that discussion.

Board Findings

The Board is of the view that the advertising program is largely directed to convincing the public of the advantages of new nuclear facilities and has little to do with established nuclear facilities or prescribed assets.

The Board finds that $2.3 million of the $6.0 million that the OPG forecast for nuclear advertising is related to development of new nuclear facilities and will therefore be disallowed as it is not related to the prescribed assets.

2.4 Nuclear Fuel

OPG forecast nuclear fuel costs of $162.4 million for 2008 and $204.2 million for 2009. Actual fuel expenses were $105 million in 2005, $104.9 million in 2006 and $113.0 million in 2007.

Compared to 2007, the 2008 fuel costs represent an increase of 47% and the 2009 forecast costs represent an increase of 81%.

OPG stated that the nuclear fuel cost forecast is based on the best information available at the time the forecast is prepared. Up to mid-2007, the spot price of uranium increased significantly over historical levels. OPG said that it attempts to manage price volatility by using a mix of both market and fixed-price contracts. OPG argued that this blended supply will ensure that any price increases are mitigated.

No intervenor objected to the OPG nuclear fuel cost forecast. Board staff noted that since OPG filed its application in late 2007, the market price of uranium has fallen sharply. OPG proposed the establishment of a nuclear fuel variance account to capture differences between forecast and actual nuclear fuel expense.

Board Findings

The Board accepts that uranium costs and fuel prices are highly volatile and OPG has developed a reasonable strategy to manage this risk through a supply portfolio consisting of both market and fixed-price contracts. The Board accepts the forecast nuclear expense. The Board has also determined that the proposed variance account should be established. This is discussed further in Chapter 7.

2.5 Capital Expenditures

Table 2-4 sets out actual and forecast nuclear capital spending. OPG proposed capital expenditures of $189 million in 2008 and $330 million in 2009. The 2009 forecast amount includes $148.8 million in possible capital spending on Pickering B refurbishment, a project that has not yet been approved by OPG's Board of Directors. Recovery of refurbishment costs is covered by specific requirements of O. Reg. 53/05. For that reason, the Board deals with the possible refurbishment costs separately in section 2.6 of this decision.

Table 2-4: Nuclear Capital Expenditures (excluding refurbishment capex)

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast
Nuclear capital expenditures	**$ 138.9**	**$ 152.2**	**$ 195.7**	**$ 189.0**	**$ 182.0**

Source: Ex: D 2-1-1

The capital expenditure plans include $27.0 million for the P2/P3 isolation project, and released projects amounting to $83.9 million for Darlington, $30.5 for Pickering A and $21.4 million for Pickering B.

Intervenors did not object to the proposed capital budgets. The Consumers Council of Canada (CCC) recommended that the Board order an external review of OPG's capital budgeting process. Citing examples of costs over-runs and project delays, CCC concluded that the capital expenditure decisions lack "the required degree of central control and accountability" necessary for effective regulatory oversight. OPG responded that such a review would be costly and without merit given the extensive evidence regarding the existing controls in OPG's capital budgeting process.

CCC noted that OPG wrote off the book values of the non-operating Units 2 and 3 at Pickering A in 2005. OPG intends, however, to capitalize the $27 million cost of the P2/P3 isolation project as part of the book value of Units 1 and 4, which continue to operate. CCC submitted that the Board should direct OPG to provide evidence in its next application to justify the capitalization of the costs of the P2/P3 isolation project. CCC also requested that OPG provide evidence that it is unable to use the nuclear segregated funds to cover the safe storage costs for Units 2 and 3.

OPG argued that review requested by CCC is unnecessary for two reasons. First, the P2/P3 isolation project costs are a minor part of the total safe storage costs for Units 2 and 3 and relate to work that is associated with the continuing operations of Units 1 and 4. Second, OPG stated that it anticipates that the costs of safe storage can be charged to the segregated funds so the additional evidence sought by CCC is unnecessary.

Board Findings

The Board accepts forecast nuclear capital expenditures as set out in Table 2-4.

With respect to capitalization of the P2/P3 isolation project costs, the Board agrees with CCC that additional evidence and analysis of the accounting for these costs would be useful. The issue arises because OPG has shut down only two units at Pickering A, and continues to operate two others. Unless OPG intends in the future to shutdown all units at a station at the same time, the accounting for unit isolation costs is likely to recur. Thus, the Board directs OPG to provide in its next application a more detailed analysis of the nature of the costs and why accounting standards require that such costs be capitalized as part of the book values of the operating units, rather than treated as costs of shutting down units.

CCC requested that the Board direct an external review of OPG's capital budgeting process. While the Board has some concern with the process, ultimately OPG produced the business case summaries which support the proposed capital expenditures. The Board views these case summaries as an important part of the assessment of the costs and benefits of the capital expenditures, and therefore they should form part of the application. The Board directs OPG to file this analysis as part of the pre-filed evidence for its next application. This will permit a more timely and meaningful review of capital expenditures by both the Board and intervenors.

2.6 Nuclear Refurbishment and New Build

The nuclear OM&A expenses as set out in Table 2-2 of this decision contain expenses related to new nuclear generation development and the possible refurbishment of Pickering B. As noted in section 2.5 of this decision, OPG's capital expenditure forecast also included $148.8 million related to the possible refurbishment of Pickering B.

O. Reg. 53/05 contains the following specific requirements in respect of OPG's recovery of costs related to refurbishment of existing units and planning new nuclear facilities:

> **6(2)4 – Costs to increase output from or to refurbish prescribed facilities**
> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.
>
> **6(2)4.1 – New nuclear development**
> The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
>
> i. the costs were prudently incurred, and
>
> ii. the financial commitments were prudently made.

Table 2-5 shows the proposed nuclear OM&A and capital expenditures that are subject to these two sections of O. Reg. 53/05. The refurbishment of Pickering B has not yet been approved by OPG's Board of Directors. Even if it had been approved, the possible capital spending in 2009 would not be included in rate base for the test period.

Table 2-5: Proposed Nuclear Refurbishment and New Build Costs

$ millions	2008		2009	
	OM&A	Capital	OM&A [15]	Capital
Pickering B refurbishment	$ 6.2	-	$ 5.1	$ 148.8
Darlington refurbishment	18.5	-	22.7	-
New build	75.3	-	67.2	-
Total	**$ 100.0**	**-**	**$ 95.0**	**$ 148.8**

Source: Ex. F2-2-1, Table 1 and Ex. K6.2

OPG stated there was no need for a prudence review of the projects because all of the costs during the test period are within approved budgets.

None of the intervenors disagreed with the company. Board staff submitted, however, that as the O. Reg 53/05 refers to “incurred” costs, the regulation applies to costs which have been expended and not those which will be expended. OPG argued that Board staff’s interpretation was incorrect, noting that the plain English meaning of “incurred” is that of “takes responsibility”. Consequently, OPG argued, O. Reg. 53/05 applies to past and future costs associated with the identified projects.

SEC submitted that the $100 million of OM&A costs for 2008 and $90 million in 2009 for nuclear refurbishment and new build should be capitalized since these costs relate to future output from the nuclear plants.

OPG replied that SEC’s recommendation should be rejected because the capitalization of these costs would be inconsistent with GAAP and OPG’s established accounting policy, which does not permit capitalization of costs related to possible projects before an alternative has been selected. OPG noted that of the three alternatives under consideration (Pickering B refurbishment, Darlington refurbishment, and a new nuclear plant), none have been selected; if any of the initiatives do not proceed, capitalization would be clearly inappropriate.

Board Findings

OPG submitted that all the OM&A costs in Table 2-5 fall within approved budgets and that all relate to planning and preparation for possible refurbishments and the

[15] The $5.1 million in 2009 OM&A for the Pickering B refurbishment is included in OPG’s Project OM&A forecast found in Table 2-2.

development of new nuclear generation facilities. The Board finds that the proposed expenditures are of the type described in Sections 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and approves the inclusion of these costs in the revenue requirement.

Board staff's submission on the meaning of "incurred" in Sections 6(2)4 and 6(2)4.1 suggests that the Board need not include any forecast amounts in the revenue requirement but could permit recovery only when OPG has actually spent money on these activities. The Board agrees with the staff's interpretation and would consider delaying recovery if there was little assurance that forecast amounts would actually be spent during the test period. However, with the announcement by Infrastructure Ontario in June 2008 that OPG's Darlington property will be the site for a new nuclear plant, it is clear that OPG will incur substantial expenditures relating to the facilities during the test period. Therefore, the Board accepts inclusion in the revenue requirement of all of the OM&A amounts shown in Table 2-5.

There is no need for the Board to approve the $148.8 million in possible capital spending on Pickering B refurbishment. OPG's Board of Directors has yet to approve proceeding with refurbishment of that station. In any event, if the project is approved during the test period, the project would not be completed during the test period and the capital costs, therefore, would not enter rate base until a later period.

The Board does not agree with SEC's submission that $100 million in preliminary costs for 2008 and $90 million for 2009 should be capitalized. SEC provided no evidence that OPG's accounting policy is contrary to GAAP.

2.7 Other Revenues

Other nuclear revenues include revenues, net of associated costs, for: ancillary services; heavy water sales and processing; tritium and other radioisotope sales; and, nuclear inspection and maintenance services. OPG forecast $100.3 million of these revenues over the 21-month test period.

No intervenors disagreed with the forecast of other nuclear revenues.

Board Findings

The Board accepts OPG's forecast of other nuclear revenues.

3 HYDROELECTRIC

The regulated hydroelectric business consists of the following prescribed facilities:

- Sir Adam Beck I and II
- Sir Adam Beck Pump Generating Station
- DeCew Falls I and II
- R.H. Saunders

The Sir Adam Beck and DeCew Falls facilities are part of the Niagara Plant Group and are located in the Niagara region. R.H. Saunders is part of the St. Lawrence Plant Group, which also includes nine unregulated facilities. R.H. Saunders is located on the St. Lawrence River near Cornwall. Together, these prescribed facilities have capacity totaling 3,332 MW.

This section of the decision addresses the following issues:

- Production Forecast
- Operating Costs
- Capital Expenditures
- Other Revenues
- Design of Payment Amount

3.1 Production Forecast

The hydroelectric production forecast for the test period is 31.5 TWh. The forecast methodology incorporates a number of components:

- Water availability forecasts
- Constraints on available water at the Niagara facilities
- Capacity to pump and store water to shift production timing
- Unit efficiency levels

OPG testified that its methodology is equally likely to over-forecast production as under-forecast production and that recent forecast deviations were attributable to differences in water conditions. OPG submitted that variations in water conditions are beyond its control and difficult to forecast, and proposed that the deferral and variance account (established under O. Reg. 53/05) be continued to capture the impact of variations in natural water conditions. No intervenor took issue with the hydroelectric production forecast.

Board Findings
The Board accepts the evidence of OPG in respect of the hydroelectric production forecast and will incorporate the forecast of 31.5 TWh into the determination of the payment amount for the test period. The issue of the deferral and variance account for water conditions is addressed in Chapter 7.

3.2 Operating Costs

The hydroelectric OM&A budget includes base OM&A, project OM&A, the asset service fee and an allocation of corporate support and centrally held costs. (This last category of costs is addressed in Chapter 4.) OPG forecast the hydroelectric OM&A budget to remain stable at $119m in both 2008 and 2009.

Table 3-1: Hydroelectric Operating, Maintenance and Administrative Expenses

$ millions	2008	2009
Base OM&A		
Niagara Plant Group	41.7	43.1
Saunders GS	14.4	14.8
Total Base OM&A	56.1	57.9
Project OM&A		
Niagara Plant Group	10.8	10.3
Saunders GS	2.1	1.8
Total Project	12.9	12.1
Allocation of Corporate Costs	47.5	46.8
Asset Service Fee	2.5	2.1
Total OM&A	**119.0**	**119.0**

Source: Ex F1-1-1, Table 1; F1-2-2, Table 1; F1-3-1, Table 1

OPG explained that the 9% increase in base OM&A from 2007 to 2008 is due to the expected hiring of additional staff, the timing of projects, and a one-time credit in 2007 from Hydro One, related to earlier work. Project OM&A relates to non-recurring expenditures which do not qualify for capitalization. OPG maintained that these expenditures are subject to the same project management and oversight as capital projects.

OPG benchmarks the hydroelectric business on reliability, safety and cost. OPG pointed out that the aggregate cost of the regulated hydroelectric facilities were in the top quartile for 2005 and 2006 as shown in a report by Haddon Jackson Associates.

Hydroelectric production is also subject to a Gross Revenue Charge ("GRC"), budgeted at $228.2 million for 2008 and $244.1million for 2009. The GRC is charged to hydroelectric generators under Section 92.1 of the *Electricity Act, 1988*. The GRC consists of a property tax component based on production levels and a water rental component of 9.5% on the gross revenue calculated from the annual generation.[16] OPG explained that it does not pay the water rental component on the DeCew facilities because it does not hold a water power lease for that facility, but it does pay compensation to the St. Lawrence Seaway Management Company for conveying water through the Welland Canal.

Board staff noted that the Board has used both a line item approach and an envelope approach to assessing OM&A forecasts. Board staff noted that another approach is to use benchmarking and that the Board has used proxies and utility comparisons as a basis for determining OM&A in other situations. No other intervenor made submissions regarding the hydroelectric OM&A test period forecast.

Board Findings

The Board accepts the forecast hydroelectric OM&A for the test period. The Board notes that the benchmarking results support a conclusion that the OM&A levels for the hydroelectric business are appropriate.

3.3 Capital Expenditures

OPG is seeking approval of amounts it has spent to increase capacity, as contemplated by O. Reg. 53/05, and it is seeking approval of its forecast capital budget for the test period. Table 3-2 sets out the level of capital expenditures in the test period and shows that the Niagara Tunnel Project is by far the largest capital expenditure for this

[16] The water rental component is set at 9.5% in O. Reg. 124/02.

business. Table 3-3 shows the additions to Gross Plant in rate base over the test period.

Table 3-2: Hydroelectric Capital Expenditures

$ millions	2008	2009
Niagara Plant Group	33.6	42.2
Niagara Tunnel Project	170.6	346.8
Saunders GS	4.6	6.6
Total	**208.8**	**395.6**

Source: Ex D1-1-1, Table 1

Table 3-3: Continuity of Hydroelectric Gross Plant

$ millions	2007 Gross Plant	2008 In-service additions	2008 Gross Plant	2009 In-service additions	2009 Gross Plant
Niagara Plant Group	2,893.6	33.1	2,926.7	41.9	2,968.7
Saunders GS	1,516.5	13.1	1,529.6	6.6	1,536.2
Total	**4,410.1**	**46.2**	**4,456.3**	**48.5**	**4,504.9**

Source: Ex B2-3-1, Tables 1 and 2

Paragraph 6(2)4 of O. Reg. 53/05 states:

> 6 (2) 4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i.if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first

> order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

OPG reported two hydroelectric projects under this section of O. Reg. 53/05: the Niagara Tunnel Project and the Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project. The Niagara Tunnel Project will increase water diversion capacity at the Beck complex and is expected to increase average annual production by 1.6 TWh. The total approved budget for the project is $985 million. The capital expenditures for 2008 and 2009 are $170.6 million and $346.8 million, respectively. This project will not be completed in the test period and therefore these amounts will not be included in rate base in the test period. The Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project will convert the existing 25Hz unit to a new 60Hz unit and return G7 to service. The approved budget for the project is $32.5 million, and the capital expenditures in 2008 and 2009 are $23.4 million and $3.9 million, respectively, and are within the approved budget. This project is expected to be completed in the test period, and the amounts are included in the test period rate base.

OPG is not seeking recovery of any costs related to “financial commitments” or “pre-engineering commitment”.

With respect to the balance of the capital budget (for projects not covered by 6(2)4 of O. Reg. 53/05), OPG is seeking approval of in-service additions of $46.2 million in 2008 and $48.5 million in 2009 associated with regulated hydroelectric capital projects. OPG explained the capital budgeting process as follows:

> All regulated hydroelectric projects reflected in this category of additional capital spending are identified and prioritized using a structured portfolio approach whereby engineering reviews and periodic plant condition assessments are performed to determine the short-term and long-term expenditures required to sustain or improve assets…After a project is initiated, a rigorous project management process is in place to provide project oversight...Project closure reports are produced for all projects and post-implementation reviews are conducted for all projects over $200,000.[17]

The following table summarizes the major projects for the hydroelectric business which fall outside of Section 6(2)4 of O. Reg. 53/05. The first two projects are included in the proposed test period rate base.

[17] OPG Argument in Chief, p. 45.

Table 3-4: Major Hydroelectric Capital Projects Not subject to O. Reg. 53/05, Section 6(2)4

Project	Description	Budget *($ million)*	In-Service Date
Unit G9 Upgrade Beck	Rehabilitate unit for the first time since 1974 to prevent unit failure, overcome a 10MW de-rating and provide additional generation through improved turbine runner efficiency.	$30.0	Dec. 2009
Replace HVAC System Project at R.H. Saunders	Replace HVAC to eliminate the costs of repairing this aging system, to eliminate the use of ozone-depleting refrigerants and to eliminate health risks associated with exposure to lead and asbestos.	$11.5	May 2008
Rehabilitate Canal Lining at Niagara	Investigate and repair the walls and liners of the open cut canal that services the Beck complex to restore and maintain their integrity, prevent erosion and weathering and improve water flow.	$55.0	Dec. 2011
Unit G3 Upgrade Project at Beck	Overhaul this unit to allow for reliable production in future, prevent unit failure and to achieve increased capacity through improved turbine runner efficiency.	$31.5	Jan. 2012
Dyke Foundation Grouting Project at Beck PGS	Upgrade the protective measures to prevent recurrence of the 1958 dyke failure due to sinkholes and other phenomena on the bottom of the reservoir.	$20.0	Dec. 2010

Source: OPG Argument in Chief, page 46.

Board Findings

The Board accepts that the Niagara Tunnel and Beck G7 conversion projects are projects which come within the scope of Section 6(2)4 of O. Reg. 53/05 and notes that both projects continue to be budgeted at the level originally approved by the OPG Board of Directors. The Board will accept the inclusion of the G7 project in rate base. Any variance between the OPG Board of Directors approved forecast and actual cost will be subject to review at a future proceeding. The Board notes that the Niagara Tunnel Project is subject to continued delay and concludes that the cost for this project is uncertain at this point. However, no finding related to the cost is required because it is not forecast to enter rate base in the test period. To the extent the final costs exceed the OPG Board approved level, the recovery of those incremental costs will be the subject of a future proceeding.

The Board also accepts the balance of the capital budget for 2008 and 2009 and the rate base consequences for those projects scheduled to become in-service during the test period.

3.4 Other Revenues

In the hydroelectric business, OPG earns additional revenues from the following activities:

- Ancillary Services
- Segregated Mode of Operation
- Water Transactions
- Congestion Management Settlement Credits

We will address each activity in turn.

3.4.1 Ancillary Services

Ancillary services provided by some of the hydroelectric generating facilities include the provision of black start capability, operating reserve, reactive support/voltage control service, and automatic generation control. OPG forecast ancillary service revenues of $32.4 million in 2008 and $33.1 million in 2009. These forecast revenues are used as an offset when determining the revenue requirement. OPG proposed that any variance between forecast and actual be captured in a deferral and variance account. No intervenor opposed the forecast.

Board Findings
The Board will accept the forecast for purposes of determining the revenue requirement. The Board's finding with respect to the proposed variance and deferral account is set out in Chapter 7.

3.4.2 Segregated Mode of Operation ("SMO") and Water Transactions ("WT")

OPG earns SMO revenues by segregating some of its R.H. Saunders generating units from Ontario and reconnecting them directly into Quebec. Revenues are received from Hydro Quebec. SMO net revenues have ranged between $9.9 million and $4.4 million over the last 3 years.[18] OPG submitted that forecasting revenues from SMO is difficult

[18] "SMO net revenues are defined as gross revenues less HOEP (or HOEP proxy costs), incremental variable costs, and costs associated with the non-regulated business. If the transaction is not indexed to HOEP but is executed at a fixed price, the HOEP for that hour is used as a proxy." (Ex. G1-1-1, p. 8)

because SMO is dependent upon hourly market conditions and advised that these revenues are expected to decline with the new high voltage transmission line between Ontario and Quebec. As a result, OPG did not propose to include a forecast of SMO net revenues as a revenue offset, but rather proposed to track the revenues in a variance account for later disposition. Further, OPG submitted that because it incurs costs and risks in undertaking these transactions it is necessary for it to have an incentive to undertake this activity. OPG pointed out that its trading function (which undertakes these transactions) has other commercial opportunities: "Without sufficient incentive to engage in SMO transactions, OPG will focus on these other opportunities."[19] OPG proposed that the net revenues be shared 50/50 with customers.

Water Transactions (WT) occur pursuant to agreements between the New York Power Authority and OPG to maximize energy production from the total water available for generation under international treaties. WT generally happen for maintenance, economic efficiency and climatic (ice) reasons, largely with the intention to salvage the water that forms part of an entity's generation share that would otherwise be spilled over Niagara Falls. WT net revenues have ranged between $8.4 million and $4.5 million over the last 3 years.[20] As with the SMO, OPG proposed to track WT revenues and to return 50% of the net revenues to customers through the use of a variance account. No forecast revenue would be included as a revenue offset in the determination of the revenue requirement.

Board staff questioned whether SMO revenues should in some way be incorporated into the revenue requirement and noted the approach used in the past for Union Gas Limited whereby a forecast of net revenues from transactional services is incorporated in the revenue requirement, and any incremental revenues are subject to variance account treatment and sharing. Board staff noted that under OPG's proposal, it is possible there could be a debit in the variance account if costs exceeded revenues.

CCC and AMPCO proposed alternative sharing formulas. CCC submitted that the customers should receive 75% of the net revenue, in recognition that the assets are included in rate base and in line with other similar sharing mechanisms in the gas industry. AMPCO submitted that a sharing ratio of 80/20 between customers and OPG would be appropriate, recognizing that OPG needs an incentive to undertake these

[19] OPG Argument in Chief, p. 74

[20] WT net revenues "are gross revenues less accommodation charges, and GRC." (Ex.G1/Tab1/Sch.1/p.11)

transactions, and that customers bear the costs underpinning these transactions and all costs are netted against the gross revenues before any sharing. CME supported AMPCO's submissions. VECC also questioned whether customers should receive the majority of the net revenues, given that the assets are included in rate base.

CCC also submitted that customers should not bear the costs of any uneconomic transactions. OPG did accept that customers should not be responsible for a negative balance in the account, but it was of the view that if individual transactions resulted in a net cost, those should be included in the account:

> Transactions are economic when entered into; if they become uneconomic, it is due to changing market conditions and prices. Transactions to manage excess baseload generation may result in a negative sub-account entry but have associated social and environmental benefits.[21]

SEC noted OPG's testimony that it has other incentives to enter into SMO transactions, including allowing OPG to manage excess baseload generation. SEC submitted that customers should receive 100% of the net revenues from these transactions as there is no real risk associated with the transactions and the transactions provide ancillary benefits to OPG which make them economic in any event. SEC also made an alternative proposal based on the transactional services model for gas distributors. Under SEC's alternative proposal, a forecast of SMO net revenues based on the average of the last three years' experience would be included as a revenue requirement offset and OPG would be entitled to retain a portion of any net revenues in excess of this forecast. SEC proposed that 75% of the forecast be included as an offset to the revenue requirement and that the excess be shared 75/25 between customers and OPG. SEC noted that in the case of Enbridge Gas Distribution Inc., this incentive structure worked to increase transactional revenues over a several year period.

OPG responded that changing the sharing would "disincent economic SMO transactions, as OPG's trading function will pursue other, more lucrative, opportunities."[22] OPG noted that unlike the transactional services in the gas utilities, the SMO and WT transactions are undertaken by staff which is also engaged in other transactional opportunities.

[21] OPG Reply Argument, p. 106.

[22] OPG Reply Argument, p. 104.

OPG also argued that the SMO transactions benefit consumers more generally because Hydro Quebec has significant water storage capacity and the SMO transactions tend to take place during off-peak hours, thereby facilitating greater generation at peak. Although OPG could not quantify the benefit, it claimed that to the extent there is more supply available at peak times, the market price (Hourly Ontario Energy Price, or HOEP) will decline, to the benefit of Ontario consumers.

With respect to SEC's proposed alternative, OPG responded that the use of a three year average for purposes of establishing a revenue offset is inconsistent with the evidence that these transactions are difficult to forecast and are expected to decline.

Board Findings

The Board agrees with intervenors that the analogy of transactional services in the natural gas industry is appropriate in the context of SMO and WT transactions. In both cases, the assets are part of the regulated business and customers pay all of the costs associated with operating these assets. OPG has an obligation to manage these regulated assets in an efficient manner, and if there are market opportunities available to offset costs, then the benefits of those transactions are appropriately shared with customers. It is also appropriate for OPG to have an incentive to optimize these revenues. The Board concludes that it is appropriate to incorporate a forecast of the net revenues from SMO and WT into the test period revenue requirement and to allow OPG to retain any incremental revenues during the test period. The Board concludes that this will provide a strong incentive to the company to pursue these transactions and will ensure that customers receive a benefit from the transactions as well.

The Board must establish the appropriate forecast to be included. The Board accepts OPG's position that it is difficult to forecast market driven activities, but concludes that a forecast of zero does not accord with the historical evidence. OPG has claimed that these transactions are likely to decline because of various developments. With respect to SMO transactions, the Board notes that only Phase 1 of the Ontario-Quebec interconnection is forecast to be in-service during the test period. With respect to WT, OPG's claim that WT activity will decline with completion of the Niagara Tunnel Project is not relevant since the project will not be completed during the test period.

OPG also argued that an enhanced incentive is required as these transactions compete for trading resources within OPG's unregulated trading business. However, the fact that the trading staff is also undertaking unregulated trading activities does not diminish

OPG's obligation to manage the regulated assets efficiently and for customers to share in those benefits. Incorporating a forecast into the revenue requirement determination will provide a positive incentive to pursue these transactions.

The Board concludes that an appropriate approach will be to include the average net revenues over the last three years into the forecast as a revenue offset in each year of the test period. In the case of SMO, the offset will be $6.6 million; for WT, the offset will be $6.9 million. (These amounts are for 2009; the amount for test period portion of 2008 will be 75% of that amount.) Any incremental revenues will accrue to OPG. This also simplifies the regulatory structure by eliminating the need for deferral accounts.

OPG has also argued that these transactions benefit customers generally through a beneficial impact on market prices. The Board finds that these benefits are too speculative to be taken into account in the determination of an appropriate sharing mechanism.

3.4.3 Congestion Management Settlement Credit ("CMSC") Payments

Under the IESO market rules, the IESO dispatches wholesale electricity generating facilities using its dispatch scheduling optimizer which determines process and schedules. Two schedules are run, one assuming no transmission or other constraints in the system and the other which considers known constraints, and which is actually used to dispatch. A Congestion Management Settlement Credit (CMSC) is paid to any market participant in compensation for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified). CMSC payments for OPG's regulated assets have ranged between $7.7 million and $12.6 million over the last three years.

OPG submitted that CMSC payments are different from SMO and WT revenues because "CMSC payments are not incremental revenues but rather an offset to lost production/revenue and increased costs."[23] OPG explained that most CMSC payments arise from constrained off situations that can result in wasted or inefficient use of water because dispatch is below the level of maximum efficiency. Similarly, constrained on situations can result in use of the generating units above the level of maximum efficiency or inefficient use of the Beck Pump Generation Station. OPG proposed to

[23] OPG Argument in Chief, p. 75.

retain all of the CMSC payments, arguing that to do otherwise would prevent it from recovering its losses associated with constrained off or constrained on situations. AMPCO submitted that OPG had failed to demonstrate that CMSC revenues are totally absorbed by the incremental costs and therefore recommended that the revenues be shared 50/50 net of incremental costs. Similarly, SEC submitted that OPG had provided no evidence to support its claim that the CMSC revenues equal the incremental unforecast costs. SEC submitted that these revenues should be treated as a revenue offset because the costs are likely included in OPG's forecasts.

OPG responded:

> CMSCs are intended to keep market participants whole, up to the operating profit they would have otherwise received, had they not been constrained-on or off by system conditions beyond their control.[24]

OPG quoted from an IESO presentation in support of this characterization. OPG maintained that if it is not able to retain the payments it will have no way to recoup the losses it would otherwise experience. OPG maintained that it would be too complex to quantify the incremental costs associated with constraint situations, but maintained that the payments, over a year, are a reasonable approximation of the impact on OPG's revenue. OPG noted that these payments are also subject to IESO review.

Board Findings

The Board will accept OPG's proposal. The losses which OPG incurs in constrained on and constrained off situations are mostly related to opportunity costs – the reduced production or less efficient production which results in lost revenues. The Board accepts OPG's evidence that the CMSC payments are designed to compensate for these losses – losses which are not otherwise incorporated into the revenue requirement. The Board will therefore not establish a deferral and variance account for this item.

3.5 Design of Payment Amount

Under the existing payment design, OPG receives $33/MWh for the first 1,900 MWh of output in any hour. Any production beyond the level of 1,900 MWh receives the market

[24] OPG Reply Argument, p. 107.

price. The objective of the incentive scheme is to provide OPG with an incentive to produce peaking supply in response to demand. The expectation is that this will benefit consumers by having a peaking resource available to improve system reliability and temper market prices through increased supply. OPG explained that this peaking capability is primarily available through the Beck complex, although there is also some capability at R.H. Saunders and DeCew.

OPG's evidence is that there have been situations when the current mechanism did not provide the right market signal to OPG because decision making is driven by the opportunity cost associated with the regulated price, rather than being driven by the market price in the off peak period. For this reason, OPG has proposed a new incentive mechanism. The formula for the proposed payment structure is as follows:

$$\sum_t [MWavg * RegRate + (MW(t) - MWavg) * MCP(t)]$$

Where:

MWavg = hourly volume or the actual average hourly net energy production over the month

RegRate = the regulated rate ($/MW) for the regulated hydroelectricity facilities

MW(t) = net energy production supplied into the IESO market for each hour of the month

MCP(t) = market clearing price for each hour of the month

Under the proposed mechanism, for production greater than the threshold level OPG will receive the market price, and for production which is less than the hourly threshold OPG will notionally pay the market price for the production shortfall. The threshold will not be set at a fixed pre-determined level; the threshold will be the actual average hourly production during the month. OPG submitted that the incremental revenues associated with the proposed mechanism (revenues over the regulated payment level) will be significantly less than under the current scheme and that the proposed mechanism results in better operational drivers because decision making is driven by market signals and not the regulated rate. OPG concluded that the proposed mechanism is therefore preferred, but noted that under the mechanism OPG is exposed to greater financial risk because it must notionally purchase any production shortfall.

OPG estimated (using market simulation modelling) that the result of this production displacing more expensive generation would reduce the hourly market price by between $.40/MWh and $1.20/MWh, with annual estimated savings for consumers of between $80m and $270m. OPG submitted that in relation to the level of benefit to consumers, the incremental benefit to OPG (revenues in excess of the revenue requirement), which is estimated at between $5 million and $19 million, is reasonable. OPG submitted:

> The proposed mechanism provides the correct signals for peaking operations since it drives the decision to pump on the spread between forecast on-peak and off-peak prices.[25]

Most intervenors expressed dissatisfaction with the proposed mechanism although they supported the objective of the mechanism and generally agreed with OPG's evidence regarding the weaknesses of the current approach. VECC concluded that the proposal should be adopted but that its operation should be tracked in a deferral account for future disposition. Energy Probe and AMPCO each submitted that the proposed mechanism should be modified. SEC submitted that the current mechanism should be continued.

In Energy Probe's view, the proposed structure is flawed because the threshold is set at the end of the month and applied retroactively. This approach results in a perverse incentive to over-use the Sir Adam Beck Pump Generating Station ("PGS") because all pumping will lower the actual monthly average rate of generation at Sir Adam Beck thereby lowering the threshold for that month; this may happen when it is contrary to the interests of the grid and consumers. Energy Probe submitted that although OPG attempted to minimize the impact of this flaw, the scenario explored in the undertaking was simplified and unrealistic, and if the PGS were used throughout the month, the impact would be multiplied by 30. Energy Probe suggested that the unintended benefit could run to $4 million to $5 million per year.

AMPCO submitted that the treatment of PGS volumes resulted in double counting which should be corrected:

> …pumping has the effect of decreasing the average monthly volume used to set the incentive mechanism threshold. Since, *ceteris paribus*, a lower threshold translates into a higher monthly average realized price for OPG than a higher threshold, the incentive for OPG to pump at the PGS is greater than indicated by

[25] OPG Reply Argument, p. 130.

> the expected differential in market prices between peak and off-peak demand periods.[26]

OPG responded that these concerns were unfounded:

> The decision to pump is based solely on the price differential between the peak and off-peak prices at a point in time, less the associated costs. It is not based on any plan to lower the average hourly volume.[27]

OPG acknowledged that pumping will reduce the average hourly volume, but noted that the benefits to consumers from increased pumping (in terms of lower peak prices) far exceed any benefit to OPG. OPG also maintained that the concern regarding potential for gaming was baseless once elements of reality were included. For example, OPG would not be able to run the PGS continuously for physical reasons.

VECC also expressed concern that the structure of the proposal could give rise to unintended consequences including raising off-peak market prices or providing OPG a bonus even if the regulated rate exceeds the average market price for the month.

A number of intervenors took the position that the perceived flaws in the methodology could be addressed by modifying the threshold. SEC submitted that the threshold should be set exogenously:

> Because the production target that triggers the incentive is OPG's own average monthly production, OPG is being rewarded simply for exceeding its own average production on a particular day, and not for exceeding a production target that is exogenously determined to meet peak production requirements.[28]

Energy Probe proposed two alternative approaches. One would be to set the threshold externally, for example using the average hourly production for the same month in the previous three years.

OPG responded that there are two benefits to setting the threshold on the basis of actual production: it is rooted in reality and it allows for a higher volume at the regulated rate than would a predetermined volume because a predetermined volume would need

[26] AMPCO Argument, p. 49.

[27] OPG Reply Argument, p. 132.

[28] SEC Argument, p. 57.

to incorporate a risk premium. OPG submitted that setting a higher pre-determined threshold would be inappropriate because it would drive OPG to maximize production:

> The objective is not to maximize OPG's production at the regulated hydroelectric facilities but to optimize economically efficient production based on market signals, which represent the value of production at various times.[29]

Similarly, OPG opposed setting the threshold based on average historical production. OPG argued that this alternative has the same flaw as any pre-determined threshold: "it disconnects the threshold from the actual water available to the regulated facilities."[30]

Energy Probe's other alternative would be to use OPG's proposed threshold, but to net out the effect of OPG's pumping at PGS on the threshold. Similarly, AMPCO proposed that 54MWh be added to the monthly total for every 100 MWh used for pumping. (This reflects that, on average, 46 MWh is generated for every 100 MWh of energy used for pumping.) In OPG's view, adjusting the hourly volume by adding pump energy losses (AMPCO's approach) is punitive because it is higher than what OPG has actually achieved in a given month. OPG submitted that setting an unreasonably high threshold is unwarranted given the significant consumer benefits to be achieved.

AMPCO also submitted that all SMO production should be included in the calculation of the monthly average production. Energy Probe submitted that a perverse incentive may exist in relation to the SMO and urged the Board to extend its preferred solution to the SMO activities as well. OPG responded that the SMO volumes are already included in the hourly volume (the threshold) but not in the actual net energy production (the amount compared against the threshold for settlement purposes).

Board staff questioned whether an independent evaluation or regular reporting of the impact and results might be warranted. AMPCO supported Board staff's suggestion that there be an independent review of the mechanism at the next case. OPG responded that while it supported a future review of the mechanism it would not be necessary or feasible to conduct an independent review in time for the next filing. OPG proposed to file its own review of the incentive's effects on its operating decisions as part of its next application.

[29] OPG Reply Argument, p. 131.

[30] Ibid., p. 132.

Board Findings

The Board will accept OPG's proposed incentive mechanism. The Board finds that the structure of the proposed mechanism is an improvement on the current mechanism as it leads to decision making based on the comparison of market prices, rather than on a comparison between the market price and regulated payment.

The Board also agrees with OPG that adopting a pre-determined threshold is not a preferred approach because the objective is not to maximize production but to optimize economically efficient production based on market signals. A number of the intervenors expressed concern with the potential for gaming opportunities under the new structure, particularly as a result of the threshold being determined after the fact. The Board concludes that these concerns are overstated. The opportunities to manipulate the average hourly production for the month are effectively limited by the physical operations of the PGS and by the financial risk which OPG faces related to its decision making. The Board accepts that OPG has an incentive to base pumping decisions on the forecast spread or risk being unable to recoup pumping costs. The Board would also note that if additional pumping takes place toward the end of a month, generation will necessarily take place before further pumping is possible, and this additional generation will increase production in the associated time period thereby raising the average production.

The Board will require OPG to present a review of the mechanism at the next proceeding, as it has undertaken to do. This review will examine the impact of the incentive structure on OPG's operating decisions.

4 CORPORATE COSTS

OPG's Corporate Costs include the costs of centralized support functions such as the Chief Information Office ("CIO"), Finance, Human Resources, Corporate Affairs, Energy Markets, Real Estate, Executive Office, Corporate Secretary and Law, and centrally held costs including Pension and Other Post Employment Benefits, Insurance, Performance Incentives and IESO Non-Energy Charges. OPG allocates corporate support and centrally held costs to its regulated businesses using direct assignment, when specific resources can be linked to a specific business, and any remaining costs are allocated based on cost drivers. Table 4-1 sets out the amounts allocated to the regulated hydroelectric and nuclear businesses.

Table 4-1: Summary of OPG Corporate Costs Allocated to Prescribed Facilities

$ millions	2006		2007		2008		2009	
	Hydro	**Nuclear**	**Hydro**	**Nuclear**	**Hydro**	**Nuclear**	**Hydro**	**Nuclear**
Support Group	19.5	210.3	21.9	236.6	28.2	263.7	28.8	262.4
Centrally Held	19.1	212.9	16.1	210.2	19.3	193.3	18.0	167.8
Total	**38.6**	**423.2**	**38.0**	**446.8**	**47.5**	**457.0**	**46.8**	**430.2**

Source: Ex. F3-1-1, Tables 2 & 3

4.1 Corporate Cost Allocation Methodology

OPG retained R.J. Rudden Associates ("Rudden") to review and provide a written report on OPG's methodology for assigning and allocating Corporate Costs, including the methodology for allocating common hydroelectric business unit costs between regulated and unregulated hydroelectric facilities. The Rudden report included a number of recommendations regarding the need for a formal quarterly review process, documentation improvements and cost driver standardization. OPG adopted the recommendations, except the recommendation to implement a standardized template to document time estimation. In OPG's view, permitting individual groups to use different formats suitable for their specific needs was an appropriate approach and meets the objective of ensuring an appropriate allocation.

OPG submitted:

> ...Rudden concluded that OPG's allocation methodology uses direct allocation where possible and appropriate allocators where direction [sic] allocation is not possible; and is consistent with best practices and applicable regulatory precedents.[31]

AMPCO and SEC expressed concern at the level of corporate costs allocated to the regulated businesses, particularly when compared to the level of costs allocated to the unregulated businesses. AMPCO noted that the increases between 2005 and 2007 for the nuclear and regulated hydroelectric costs were 25% and 38% respectively, while the increase for the unregulated costs was 6.5%.

OPG maintained that it has fully explained the growth in these costs. Whereas the intervenors have compared costs between 2005 and 2007, OPG argued that a better comparison would be between 2005 and 2009, to include the test period. Costs allocated to unregulated operations increase by 17% in that period; total corporate costs increase by 22%; and costs allocated to nuclear increase by 21%. Costs allocated to hydroelectric increase by a greater amount, 69%, because of the high levels of capital spending in the regulated hydroelectric business, especially relative to the capital spending in the unregulated business. OPG also noted that the overall level of costs allocated to regulated operations, as a percentage of total corporate costs, has ranged between 68% and 71% over the period and is under 70% for the test period.

CME argued that the allowance for the corporate cost allocation should be limited to the 2006 level and that the revenue requirement for the test period should be reduced by $40 million as a result:

> We submit that the Rudden Study on which OPG relies only operates to establish the reasonableness of OPG's 2006 allocation of corporate costs. Since there is no independent evidence to justify the increase in the allocations of corporate costs which OPG seeks to recover in its test year revenue requirement, the allocated amounts should remain at their 2006 level.[32]

OPG responded that Rudden used 2006 data because that was the most recent data available when the application was filed in November 2007. OPG's testimony is that the

[31] OPG Argument in Chief, p. 83.

[32] CME Argument, p. 62.

methodology has been applied consistently for 2008 and 2009 forecast costs, and that the auditors have confirmed its application to 2007 costs.
AMPCO submitted that a more comprehensive cost allocation methodology should be in place to ensure there is no cross-subsidization of the unregulated business:

> AMPCO recommends that the Board establish for OPG mandatory requirements based upon principles that reflect the policies underlying the recently amended Affiliate Relationship Code for Electricity Transmitters and Distributors. Specifically OPG should be required to satisfy the same principles with respect to Transfer Pricing, restrictions on sharing of Confidential Information, and similar reporting protocols to the Chief Compliance Officer so that transparency can be achieved to ensure that ratepayers are not subsidizing OPG's unregulated business.[33]

OPG responded that an affiliate relationship type code would impose costs without additional benefits. OPG noted that it is a single company without affiliates, and argued that it has developed a fair and reasonable methodology for allocating common corporate costs which is consistent with the ARC provisions and has been independently reviewed.

A number of intervenors proposed further independent evaluation of the corporate cost allocation. Board staff suggested there should be an external review of the corporate costs allocated to the prescribed assets, noting the Board's decision in Enbridge Gas Distribution's 2006 rates proceeding which required an independent review of these costs. VECC also submitted that an external evaluation was warranted given the significant increase in costs allocated to the regulated operations. While CCC recognized the Rudden report as an important first step, it submitted that the Board should direct OPG to undertake an independent study of internal corporate processes to ensure that services are not duplicated and the processes for review, reporting and approval are effective.

OPG responded that it will submit an independent evaluation of its corporate cost allocation methodology, and its use of the methodology in the test period, as part of the next application. OPG submitted, however, that an independent review of its corporate processes was not warranted and cited various internal activities it undertakes to ensure these costs are reasonable.

[33] AMPCO Argument, p. 36.

CCC also recommended that OPG should continue benchmarking all corporate support and administrative departments. CCC submitted that intervenors should have a role in establishing the terms of this benchmarking. CCC suggested this approach could reduce regulatory time and expense. OPG responded that it intends to continue benchmarking CIO, Finance and Human Resources. However, OPG submitted that it would be inappropriate for the Board to direct that intervenors be involved in establishing the terms of benchmarking. In OPG's view, this is appropriately the responsibility of OPG. OPG noted that the example of the Enbridge CIS intervenor involvement followed from a decision in which the Board rejected a proposed 12-year contract and cited deficiencies in the company's evidence; in OPG's view no comparable circumstance is present in this application which would warrant intervenor involvement.

Board Findings

The Board will accept the allocation of corporate costs for the test period. The percentage increase in costs allocated to the nuclear business between 2005 and 2009 is comparable to the overall increase in corporate costs during that period. The increase in costs allocated to the hydroelectric business is much larger in percentage terms than the overall increase, but the Board accepts that this increase is related to the relative size of the Niagara Tunnel Project and its impact on the resulting allocations. The Board notes that the allocation of total costs to the regulated businesses (in percentage terms) is in line with historical levels. Intervenors have criticized the Rudden report on the basis that it used 2006 data. The Board finds that using 2006 data was acceptable in the circumstances, given the timing of the report and the availability of actual data.

AMPCO has recommended that OPG be subject to requirements similar to the *Affiliate Relationships Code for Electricity Distributors and Transmitters*. The Board concludes that such an approach is not necessary at this time because the provisions of the Code related to shared corporate services (namely, pricing based on fully allocated costs) are essentially the same as the approach adopted by OPG for the allocation of corporate costs. An appropriate cost allocation methodology and independent review can ensure there is no cross-subsidy between OPG's regulated and unregulated businesses. The Board notes that OPG has undertaken to present another independent evaluation of the corporate cost allocation as part of its next application. The Board accepts this undertaking and will direct OPG to file such a study.

The Board expects the next independent review to include an evaluation of the cost allocation methodology and consideration of the Board's "3-prong test". This test was addressed in the Board's decision for Enbridge Gas Distribution 2006 rates.[34] That decision stated:

> The 3-prong test was defined in the Board's Decision in EBRO 493/494 and can be summarized as follows:
>
> > Cost incurrence: Were the corporate centre charges prudently incurred by, or on behalf of, the companies for the provision of services required by Ontario ratepayers?
> >
> > Cost allocation: Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?
> >
> > Cost/Benefit: Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?
>
> The costs must pass all three tests. If a service, or the scope of service, is not needed by the gas distribution utility, then the cost should not be recovered from ratepayers. This is so even if the benefits may exceed the costs in question.[35]

The Board encourages OPG to continue with its benchmarking activities in the corporate areas it has identified. While it is often advisable to consult with intervenors where practicable in these activities, the Board will not require OPG to involve intervenors in these activities at this time.

4.2 Corporate Costs – Regulatory Affairs

CCC submitted that OPG's regulatory affairs budget for 2009 should be reduced by 50% because the 2008 budget, which included preparation of studies to support the application, is not an appropriate baseline for the 2009 budget. CCC stated that a variance account could be established to capture deviations from budget. SEC noted the 85% increase in the Corporate Affairs budget between 2006 and 2008, and submitted that costs for consultants and purchased services for regulatory affairs should be subject to deferral account treatment because many of these fees are beyond OPG's control and the timing of the next rate proceeding is uncertain.

[34] EB-2005-0001/EB-2005-0437, *Decision with Reasons*, February 9, 2006.

[35] Ibid., pp. 79-80.

OPG responded that it will be filing a new application in 2009 and therefore the regulatory affairs budget is not excessive. OPG submitted that a deferral account is not required because it would not meet a materiality threshold in the context of OPG's operating costs.

Board Findings

The Board will not make any adjustments to the regulatory affairs budget. It is clear that OPG will be filing another application shortly after this decision is issued. Therefore, the regulatory affairs costs for 2009 are likely to be of the same magnitude as the budget for 2008. The Board agrees with OPG that a deferral account is not necessary for regulatory costs. In the context of OPG's overall situation, these costs are not material.

5 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

OPG's balance sheet includes substantial liabilities for nuclear used fuel management, nuclear decommissioning, and low- and intermediate-level waste management. At December 31, 2007, those liabilities totalled almost $10.8 billion. They are projected to grow to $11.7 billion by the end of 2009.

The regulatory treatment of these liabilities was a major issue in this proceeding. The nuclear liabilities are relevant to the determination of: the amount of costs with respect to the Bruce nuclear generating stations (Chapter 6); the balance in the nuclear liability transitional deferral account (this chapter and Chapter 7); and, rate base and cost of capital (Chapter 8).

This chapter first provides some factual information and background on OPG's obligations for waste management and decommissioning at each of its nuclear facilities, the arrangements in place to fund those liabilities, and how the company presents them in its consolidated financial statements. It then summarizes OPG's proposed treatment of nuclear liabilities in the calculation of the revenue requirement, the balance in the Section 5.1 deferral account, and the calculation of Bruce costs. The balance of the chapter deals with OPG's rationale for its proposal, the submissions of the other parties, and the Board's findings.

5.1 Background

5.1.1 Nuclear liabilities

OPG is legally responsible for the ongoing, long-term management of radioactive waste from each of its nuclear facilities – Pickering A, Pickering B, Darlington, Bruce A, and Bruce B. OPG is also responsible for decommissioning the nuclear plants after the plants are shut down permanently. The Bruce A and Bruce B stations are not prescribed facilities. They are owned by OPG but have been leased to, and are operated by, Bruce Power L.P.

The amounts of OPG's nuclear waste management and decommissioning liabilities (collectively the "nuclear liabilities") are based on the costs OPG expects to incur up to and beyond the termination of operations and the closure of nuclear facilities. Costs will be incurred to dismantle, demolish and dispose of facilities and equipment, to remediate and restore the plant sites, and to manage nuclear used fuel and low- and intermediate-level waste material.

OPG estimated that the undiscounted amount of future cash outflows for waste management and station decommissioning at the end of 2007 was $24 billion (measured in 2007 dollars). The amounts and timing of future cash outflows are based on significant assumptions and are necessarily subject to considerable uncertainty. OPG's current nuclear waste management and decommissioning plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown, and to 2065 for placement of used fuel into a long-term depository followed by extended monitoring.

OPG measures the nuclear liabilities by discounting the estimated cash flows for the time value of money. When OPG acquired the generation business of Ontario Hydro on April 1, 1999 and commenced operations, the nuclear liabilities were less than $6.5 billion, which equalled the expected future cash outflows discounted at 5.75%.[36] By the end of 2007, the liabilities had grown to $10.8 billion. The principal reasons for the increase since 1999 are accretion expense (as time passes, the present value of estimated cash outflows increases) and a material upward revision to estimated future cash flows that was recognized at the end of 2006.

Table 5-1 is a continuity schedule of nuclear liabilities from the beginning of 2005 to the end of 2009. For liabilities established before the end of 2006, the discount rate is 5.75%. For liabilities recorded on December 31, 2006, the discount rate is 4.6%, which was based on bond market conditions at that time.

[36] OPG 1999 consolidated financial statements, Note 7.

Table 5-1: OPG's Actual and Forecast Nuclear Liabilities

$ millions	2005	2006	2007	2008 Forecast	2009 Forecast
Opening balance	$ 8,150	$ 8,567	$ 10,328	$ 10,781	$ 11,207
Accretion	467	490	575	603	626
Accrue variable expense	34	38	76	48	39
Liabilities settled	(84)	(153)	(198)	(225)	(193)
Change in cost estimates	-	1,386	-	-	-
Ending balance	**$ 8,567**	**$ 10,328**	**$ 10,781**	**$ 11,207**	**$ 11,679**
By facility:					
Pickering/Darlington	$ 5,009	$ 5,714	$ 5,921	$ 6,182	$ 6,466
Bruce	3,558	4,614	4,860	5,025	5,213

Source : Exhibit J1.5.

At December 31, 2007, total nuclear liabilities of $10,781 million were comprised of a liability for used fuel management of $5,938 million and a liability for nuclear decommissioning and low- and intermediate level waste management of $4,843 million. OPG advised that its nuclear liabilities are substantially higher than the liabilities of nuclear operators in the United States, which do not directly bear the risk of managing nuclear fuel waste. In the U.S., the federal government bears the liability for managing used fuel and collects a per kWh charge from operators.

5.1.2 Funding

At the end of 1999, the year that OPG assumed the nuclear waste management and decommissioning obligations from Ontario Hydro, the nuclear liabilities were largely unfunded. There was only $367 million segregated to satisfy the liabilities compared to total nuclear liabilities of $6,591 million.[37]

In 2002, OPG and the Province of Ontario finalized the Ontario Nuclear Funds Agreement (ONFA). That agreement established two segregated funds – a used fuel fund and a decommissioning fund – to be held by an independent custodian. The used fuel fund will be used to fund future costs of long-term nuclear used fuel waste management. The decommissioning fund will be used to pay for the cost of

[37] OPG 1999 consolidated financial statements, Note 7.

decommissioning the plants and the cost of managing low- and intermediate-level waste.

The ONFA requires OPG to make quarterly payments to the funds. OPG's payments are determined by a Provincially-approved reference plan (Approved Reference Plan) that sets out the estimated costs to meet OPG's nuclear waste management and decommissioning obligations. The ONFA requires OPG to prepare reference plans when required by law or regulatory bodies, or every five years, whichever is earlier. The current Approved Reference Plan was approved by the Province in December 2006. The ONFA also requires OPG to prepare a new or amended reference plan in the event of a material change, which includes reductions in the remaining operating period for a nuclear station and any change in circumstances or assumptions that would cause a change in estimated costs by more than an agreed amount.

Under the ONFA, the Province limits OPG's financial exposure for used fuel management with respect to the first 2.23 million used fuel bundles, a threshold that OPG expects will be reached in 2011. OPG is fully responsible for costs of managing used fuel bundles in excess of that amount. The Province also guarantees an annual rate of return of 3.25% above the Ontario Consumer Price Index on the portion of the used fuel fund related to the first 2.23 million used fuel bundles. Actual returns in excess of the guaranteed return accrue to the Province, not OPG.

OPG contributed approximately $4.2 billion to the segregated funds during the five years ended December 31, 2007.[38] The Province made a substantial one-time contribution to the decommissioning fund in 2003. The decommissioning fund had a fair value of approximately $5.1 billion at December 31, 2007 and is considered to be overfunded under the provisions of the ONFA.

At the end of 2007, the fair value of the investments held in the used fuel fund was approximately $4.2 billion, after deducting $511 million relating to excess earnings that accrue to the Province. A revised schedule for OPG's contributions to the used fuel fund was approved by the Province in March 2008. That schedule shows OPG making contributions of approximately $2.1 billion to the used fuel fund over the ten-year period 2008 to 2017, with smaller amounts being contributed thereafter.

[38] Exhibit J15.11, page 4.

5.1.3 Financial reporting

For external financial reporting purposes, OPG accounts for its nuclear liabilities in accordance with the requirements of Section 3110 of the Handbook of the Canadian Institute of Chartered Accountants (CICA).

Section 3110 defines an asset retirement obligation (ARO) as:

> [A] legal obligation associated with the retirement of a tangible long-lived asset that an entity is required to settle as a result of an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel.[39]

OPG's nuclear liabilities meet the definition of an ARO.

Section 3110 requires that an entity recognize the fair value of an ARO as a liability on its balance sheet in the period in which it is incurred, provided a reasonable estimate of fair value can be made. The fair value of an ARO is generally calculated by discounting expected future cash flows, the approach used by OPG.

When an ARO is recognized as a liability, Section 3110 requires that an equal amount be recorded as an increase in the net book value of the related long-lived assets. The addition to net book value is referred to as an asset retirement cost (ARC). An ARC is amortized over the useful life of the assets in the same manner as any other capital cost related to the asset.

Section 3110 is essentially the same as the United States accounting standard on asset retirement obligations issued by the Financial Accounting Standards Board (FASB) in 2001.

The net book values of OPG's nuclear stations include material amounts of unamortized ARC, as shown in Table 5-2.

[39] CICA Handbook Section 3110, "Asset Retirement Obligations," paragraph .03 (a), issued March 2003. OPG adopted Section 3110 in 2003 and retroactively applied the new standard to financial statements for earlier periods.

Table 5-2: Nuclear ARO and ARC Amounts on OPG's Balance Sheet

$ millions at December 31	2005	2006	2007	2008 Forecast	2009 Forecast
Pickering and Darlington					
Fixed asset net book value	$ 2,493	$ 2,924	$ 2,826	$ 2,762	$ 2,630
Unamortized ARC in net book value	$ 1,013	$ 1,435	$ 1,301	$ 1,181	$ 1,061
Unamortized ARC as % of NBV	41%	49%	46%	43%	40%
Nuclear liabilities (ARO)	$ 5,009	$ 5,714	$ 5,921	$ 6,182	$ 6,466
Bruce					
Fixed asset net book value	$ 492	$ 1,271	$ 1,195	$ 1,128	$ 1,063
Unamortized ARC in net book value	$ 388	$ 1,188	$ 1,128	$ 1,080	$ 1,032
Unamortized ARC as % of NBV	79%	93%	94%	96%	97%
Nuclear liabilities (ARO)	$ 3,558	$ 4,614	$ 4,860	$ 5,025	$ 5,213

Sources: Ex. B3-3-1, Tables 1 and 2; Ex. B3-5-1, Tables 1 and 2; Ex. G2-2-1, Table 2; Ex. J1.5; and Ex. J15.1, Addendum #2.

An entity must recognize period-to-period changes in the ARO liability due to the passage of time (accretion expense) and due to revisions to the timing or amounts of the expected future cash flows required to carry out the asset retirement activities. Accretion expense is a charge against earnings. Increases or decreases in AROs due to changes in cost estimates are accounted for the same as the initial recognition of an ARO – they give rise to an equivalent amount of ARC, which is an adjustment to the net book value of the related long-lived assets.

At the end of 2006, OPG revised its cost estimate for nuclear waste management and recorded a $1,386 million increase in the nuclear liabilities and a corresponding increase in the net book values of the nuclear plants ($509 million related to Pickering and Darlington and $878 million related to the Bruce stations).

In its GAAP income statement, OPG books expenses for accretion, depreciation of ARC, and variable waste management expenses (this last expense arises because the nuclear liabilities increase as more nuclear fuel is used each period). OPG also books the earnings on, and change in fair value of, assets held in the segregated funds. Table 5-3 shows the forecast pre-tax charge in OPG's income statement due to the nuclear liabilities and the segregated funds.

Table 5-3: Forecast GAAP Expense – Nuclear ARO, ARC, Segregated Funds

$ millions, periods ending December 31	2008 nine months	2009	Total
Pickering and Darlington			
Depreciation of ARC	$ 90	$ 120	$ 210
Nuclear waste variable expense	16	23	39
Accretion expense	251	344	595
Segregated fund earnings	(186)	(264)	(450)
Total - Pickering, Darlington	**$ 171**	**$ 223**	**$ 394**
Bruce			
Depreciation of ARC	$ 36	$ 48	$ 84
Nuclear waste variable expense	19	17	36
Accretion expense	201	282	483
Segregated fund earnings	(176)	(262)	(438)
Total - Bruce	**$ 80**	**$ 85**	**$ 165**

Sources: Ex. H1-1-3, page 2; Ex. J1.5; Ex. J7.2; Ex. 8.1; Ex. J15.1, Addendum #2.

5.2 OPG's Proposed Treatment of Nuclear Liabilities

Section 6(2)8 of O. Reg. 53/05 requires the Board to ensure that OPG recovers the "revenue requirement impact of its nuclear decommissioning liabilities arising from the current approved reference plan". OPG proposed the following ratemaking approach for nuclear liabilities related to the prescribed facilities, and the related segregated funds, for the test period:

- Depreciation of the ARC component of the net book value of the prescribed nuclear plants is included in the test period revenue requirement.
- Nuclear waste variable costs for Pickering and Darlington are included in the revenue requirement as either fuel costs or depreciation.
- The rate base for 2008 and 2009 would include the average net book values of OPG's Pickering and Darlington nuclear stations. Those net book values include significant amounts of ARC as shown in Table 5-2 above. OPG proposed

applying its debt rate and return on equity to the entire rate base, including unamortized ARC, to determine the revenue requirement.

- Accretion expense and the earnings on segregated funds, both of which affect OPG’s reported income under GAAP, are excluded from the revenue requirement under OPG’s proposal.

OPG referred to this approach as the “rate base method.”

Section 6(2)9 of O. Reg. 53/05 requires that the Board ensure OPG recovers all of the costs it incurs with respect to the Bruce Nuclear Generating Stations (“Bruce stations”). Section 6(2)10 requires that if OPG’s revenues from the lease of the Bruce stations exceed its costs, the excess shall be applied to reduce the payment amounts for the Pickering and Darlington facilities. OPG proposed to use the rate base method for nuclear liabilities to calculate its test period costs of the Bruce stations.

Table 5-4 sets out the amounts OPG proposed to recover during the test period in respect of nuclear liabilities. The amounts for depreciation of ARC and nuclear waste variable expenses are the same as the amounts OPG forecasts it will charge to expense in its financial statements (as shown in Table 5-3). For ratemaking purposes, OPG proposed to ignore accretion expense and earnings on segregated funds. Instead, OPG proposed to recover $175 million as a return on the average unamortized ARC of the Pickering and Darlington facilities ($51 million of deemed interest and a return on equity of $124 million). OPG also proposed to include a $161 million return on unamortized ARC in its forecast costs related to the Bruce stations (deemed interest of $47 million and a return on equity of $114 million).

Table 5-4: OPG's Proposed Recoveries Related to Nuclear Liabilities

$ millions, periods ending December 31	2008 nine months	2009	Total
Pickering and Darlington			
Depreciation of ARC	$ 90	$ 120	$ 210
Nuclear waste variable expense	16	23	39
Cost of capital:			
Interest	23	28	51
ROE	56	68	124
Total - Pickering, Darlington	**$ 185**	**$ 239**	**$ 424**
Bruce			
Depreciation of ARC	$ 36	$ 48	$ 84
Nuclear waste variable expense	19	17	36
Cost of capital:			
Interest	20	27	47
ROE	50	64	114
Total - Bruce	**$ 125**	**$ 156**	**$ 281**

Source: Ex. H1-1-3, page 2.

The increase in the nuclear liabilities that OPG recorded at the end of 2006 occurred before the Board assumed responsibility for setting the payment amounts. That increase is nonetheless relevant to this application because the deferral account mandated by Section 5.1 of O. Reg. 53/05 requires OPG to record the "revenue requirement impact" of that increase in the nuclear liabilities for the period up to the date of the Board's first order.

OPG proposed to adopt the same rate base method to calculate the balance in the Section 5.1 deferral account that it proposes to adopt for the test period revenue requirement for Pickering and Darlington. That treatment, which OPG proposed should apply to both the increase in 2006 in the Pickering/Darlington nuclear liabilities and the increase in nuclear liabilities related to the Bruce stations, resulted in OPG recording $75.4 million as a "return on rate base" in the Section 5.1 deferral account.

5.3 The Issues and Board Findings

The ratemaking treatment for nuclear liabilities is complex, and it is made more complex in this case because the issues involve two types of facilities (Pickering and Darlington, which are prescribed facilities under O. Reg. 53/05, and the Bruce stations, which are not prescribed facilities) and two time periods (the test period, and the period prior to the date of the Board's first order.) Some of the relevant issues and considerations are common to both time periods and types of facilities while other issues are unique to a particular time period or type of facility. The Board has chosen to deal with OPG's rationale for its proposal, the positions of the parties, and the Board's findings under four headings:

- Interpretation of O. Reg. 53/05. OPG submitted that the regulation requires the Board to allow OPG to recover costs related to nuclear liabilities using the rate base method. Several intervenors disputed that claim and submitted that the Board has the discretion under the regulation to adopt other methods. Section 5.3.1 below deals with this issue. The Board finds that O. Reg. 53/05 does not obligate the Board to accept OPG's use of the rate base method and that the Board has the discretion to set the revenue requirement using other methods.
- Method of recovering the costs of nuclear liabilities of the prescribed facilities. Section 5.3.2 below reviews the arguments made in favour of and against the rate base method, and the alternatives suggested by intervenors. This section is restricted to the test period revenue requirement of the nuclear liabilities of the prescribed nuclear facilities, Pickering and Darlington. The Board has determined that OPG's revenue requirement related to the cost of nuclear liabilities for the prescribed facilities should not be calculated using the rate base method. Instead, the Board finds that OPG shall use a method that provides separate rate base treatment for the amount of unfunded liabilities.
- Section 5.1 and 5.2 deferral accounts. Section 5.3.3 below deals with the question of how the revenue requirement impact of the 2006 change in nuclear liabilities should be calculated for purposes of the deferral account mandated by Section 5.1 of the regulation. It also addresses how OPG should calculate entries into the deferral account mandated by Section 5.2 of O. Reg. 53/05, in the event OPG records a change in its nuclear liabilities after the date of the Board's first order. The Board finds that for each account the revenue requirement impact will

be calculated using the method that was used to set the revenue requirement during the period of time which the account covers.

- Bruce nuclear liabilities. The issue is whether the costs of nuclear liabilities related to the Bruce stations, which are not prescribed facilities, should be calculated in the same manner as the costs related to the prescribed facilities, or whether a different methodology should be used. This issue is addressed in Chapter 6 of this decision.

5.3.1 O. Reg. 53/05 and nuclear liabilities

Section 6(1) of the regulation states: "Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act." Nuclear liabilities are referred to in Section 6(2)8, which requires that: "The Board shall ensure Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan." The regulation does not contain definitions of "revenue requirement" or "revenue requirement impact."

OPG took the position that the regulation requires the Board to allow OPG to recover nuclear liability costs using the rate base method. OPG submitted that both:

(i) Section 6(2)5(i) of O. Reg. 53/05, which requires the Board to accept the amounts of assets and liabilities as set out in OPG's 2007 audited financial statements, and

(ii) Section 6(2)6(ii), which states that Section 6(2)5 applies to values relating to the revenue requirement impact of accounting and tax policy decisions,

make it clear that asset values resulting from accounting policy decisions approved by OPG's auditors and OPG's Board of Directors must be accepted by the Board in making its first order.

The net book value of nuclear fixed assets set out in OPG's 2007 audited financial statements includes material amounts of unamortized ARC (as shown in Table 5-2 above). OPG submitted that those fixed asset amounts must be accepted into rate base because those amounts appear in the financial statements. OPG claimed that any other interpretation of Sections 6(2)5 and 6(2)6 would "render them meaningless and totally ineffective." OPG asserted that accepting ARC into rate base but attaching a different cost of capital to that element of rate base would contravene the clear intention of those two sections of the regulation.

OPG also submitted that O. Reg. 53/05's provisions for the deferral accounts authorized by Sections 5.1 and 5.2 support its view that the test period revenue requirement must be set using the rate base method. Those deferral accounts capture the "revenue requirement impact" of certain changes in nuclear liabilities before (Section 5.1) or after (Section 5.2) the date of the Board's first order. Section 6(2)7 requires those revenue requirement impacts to be based on four items as "reflected in" OPG's financial statements, including a "return on rate base."[40] OPG argued that there would be no meaning to this provision if the regulation did not require the Board to use the rate base method. OPG argued that it would be capricious and arbitrary to employ one method to calculate deferral account balances related to *changes* to nuclear liabilities as a result of new reference plans (Sections 5.1 and 5.2) and a different method to set the revenue requirement impact of those changes for the test period (Section 6(2)8).

CCC, CME (supported by AMPCO), SEC, VECC and Board staff disagreed with OPG's interpretation of O. Reg. 53/05.

CCC submitted that the regulation does not directly, or by necessary implication, require the Board to accept the rate base method for the costs of nuclear liabilities. CCC also submitted that although the Board is required by Section 6(2)5 to accept amounts set out in OPG's financial statements, the Board is not required to adopt all of the accounting and ratemaking assumptions therein.

CME acknowledged that Sections 6(2)5 and 6(2)6 require the Board to accept amounts set out in OPG's financial statements. CME submitted, however, that the "revenue requirement impact" of nuclear liability costs is an item of regulatory policy, not an item of tax or accounting policy. CME argued that the regulation does not empower OPG and its auditors to make a regulatory policy determination with respect to the recovery of costs associated with nuclear liabilities. CME also submitted that if the recovery of the costs of nuclear liabilities is a matter of accounting policy, and not regulatory policy, then GAAP provisions relating to expensing of nuclear liability costs should apply. Yet,

[40] The four items are: return on rate base; depreciation expense; income and capital taxes; and fuel expense.

CME noted, OPG's rate base method disregards and does not apply GAAP to calculate the amount of expense related to nuclear liabilities.

SEC urged the Board to reject OPG's proposition that the inclusion of nuclear liability costs in the revenue requirement has been predetermined by the regulation. SEC observed that OPG does not cite any specific provision of O. Reg. 53/05 that directs the Board to accept the rate base method and noted that "revenue requirement impact" is not defined in the regulation. SEC submitted that the regulation leaves it to the Board to determine the revenue requirement related to the cost of nuclear liabilities.

SEC disagreed with OPG's submission that the reference to "return on rate base" in Section 6(2)7, which deals with the deferral accounts for changes in nuclear liabilities, supports a conclusion that the regulation requires OPG's rate base method. SEC pointed out that while Section 6(2)7 requires revenue requirement impacts to be based on four items as reflected in OPG's audited financial statements, one of which is a "return on rate base," OPG's audited financial statements do not contain any items called "return" or "rate base." SEC argued that on a plain reading of Section 6(2)7, <u>no</u> return on rate base could be permitted as there is no item called "return on rate base" in the financial statements; a plain reading of the other parts of Section 6(2)7 would lead to similarly absurd results. [41] For these reasons, SEC submitted that the government, in enacting the regulation, did not intend Section 6(2)7 to be read literally, and did not intend that the entire decision-making responsibility for recovering the costs of nuclear liabilities be granted to OPG's Board of Directors.

SEC submitted that:

> … this Board should not fetter its discretion to determine payment amounts under s. 78.1 on the basis of an implied direction in s. 6(2)7. The Board should only decline jurisdiction when its mandate is clearly and expressly circumscribed, which is not the case here. The alternative is for the Board to implement rate recovery for nuclear negative salvage on a basis that the Board knows (or at least suspects) is not just and reasonable, on the theory that the government

[41] Of the three remaining items, SEC pointed out that depreciation expense is included in the financial statements but not normally disaggregated into line items; income and capital taxes are accounted for differently for regulatory and accounting purposes, and a literal reading of section 6(2)7 would require the application of conventional deferred tax accounting to the regulatory sphere, a significant and major change in regulatory process that is unlikely to have been implemented by the government without express direction; and fuel expense, another of the four items, is not separately set out in the financial statements. (SEC Argument, paragraph 194.)

> may have indirectly limited the Board's jurisdiction to do what is right.[42] (emphasis in original)

VECC submitted that whether and how a particular accounting item is included in the regulatory construct of "rate base" is entirely at the discretion of the Board, and is not something imposed on the Board by a non-regulatory accounting policy. VECC acknowledged that although the accounting treatment for an item can provide guidance in a regulatory context, the method of accounting is not determinative of the appropriate regulatory treatment.

Board staff submitted that Sections 6(2)5 and 6(2)6, on which OPG relies in its argument, must be read in conjunction with Section 78.1(4) of the *OEB Act*[43] and Section 6(1) of O. Reg. 53/05. Board staff concluded that:

> … while the Board must accept the amounts and certain values set out in the audited financial statements when making its first order, the Board's discretion in dealing with matters which are placed in rate base, either through the operation of the Regulation or as a result of its own determination of the composition of rate base, remains. Board staff submits that it is open to the Board to determine whether a different cost of capital should be applied to an element of rate base.[44]

In its reply argument, OPG submitted that O. Reg. 53/05 does not confer any jurisdiction on the Board with respect of the recovery of the cost of nuclear liabilities. OPG asserted that the regulation merely confirms the continuation of what OPG describes as the status quo – the use of the rate base method.

OPG argued that the phrase "revenue requirement impact" used in Section 6(2)7 does not convey total discretion to the Board, as CME and the other intervenors suggest. In OPG's view, the role of the Board is quite limited. OPG submitted that the phrase "to the extent the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts" in Section 6(2)7:

[42] SEC Argument, paragraph 201. "Nuclear negative salvage" is the term that SEC used to describe nuclear decommissioning liabilities.

[43] Section 78.1(4) of the *OEB Act* states: "The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment."

[44] Board Staff Argument, page 14.

> … obligates the OEB to ensure that OPG has accurately calculated the "revenue requirement impacts" and recorded the correct figures in the deferral account; it has nothing to do with the methodology that the OEB must follow for determining the "revenue requirement impacts."[45]

OPG claimed that a conclusion that the Board retains discretion over the composition of rate base and the return on ARC would make a complete mockery of Sections 6(2)5 and 6(2)6 of the regulation. OPG asked: "If the OEB must accept the ARC as a fixed asset but is free to assign it a zero cost [a position advocated by some intervenors], how has the Board "accepted" anything?"[46]

OPG claimed that the Province of Ontario knew, when it approved O. Reg. 53/05 in 2005, that the initial payment amounts were set using the rate base method for the costs of nuclear liabilities. OPG submitted this is an important factor to be considered when interpreting Sections 6(2)5 to 8 of the regulation. OPG also claimed that the Province is aware that OPG used the rate base method in preparing this application and the interpretation of the regulation that it was putting forward, namely, that the regulation required the Board to ensure OPG recovers nuclear liability costs calculated using the rate base method. OPG stated: "As the sole shareholder, if OPG's request was out of line with the intent of O. Reg. 53/05, it would be reasonable to expect that the Province would have so advised the company."[47]

Board Findings

The Board does not accept OPG's position that O. Reg. 53/05 requires the Board to ensure OPG recovers nuclear liability costs calculated using the rate base method. The Board finds it has discretion to determine the method that OPG should use to calculate and so recover the revenue requirement impact of the nuclear liabilities.

Section 6(2)8 of O. Reg. 53/05 obligates the Board to ensure OPG recovers the revenue requirement impact of its nuclear liabilities. Section 6(1) of O. Reg. 53/05 specifies that the Board "may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts." The only restriction in Section 6(1) is that a Board order is subject to the provisions of section 6(2). The Board has concluded that none of the provisions of section 6(2) require the

[45] OPG Reply Argument, page 127.

[46] OPG Reply Argument, page 126.

[47] OPG Reply Argument, page 126.

rate base method be used to calculate the revenue requirement impact referred to in Section 6(2)8.

The Board reached this conclusion for several reasons.

First, the regulation does not define "revenue requirement impact" and does not state anywhere that the rate base method must be used to determine the cost of nuclear liabilities. In its role as economic regulator of electric and natural gas utilities, the Board has many years of experience in setting the revenue requirements of the entities it regulates. Determining what items should be included in an entity's revenue requirement, and how those items should be measured, is one of the most important functions of an economic regulator. Had the government intended that the Board relinquish the jurisdiction to determine how the revenue requirement should be calculated, it could have included clear and unambiguous language to that effect in the regulation. It did not do so.

The Board notes that OPG was unable to provide any examples from other North American jurisdictions of the rate base method being used to calculate the costs of nuclear liabilities. While the lack of examples does not invalidate the method, it certainly casts doubt on OPG's contention that, notwithstanding the lack of any explicit statement, the government clearly intended that only the rate base method be used. The Board cannot accept that the government intended to require the Board to accept a method not known to be used in any other jurisdiction yet did not consider it necessary to make this requirement explicit in the regulation.

Second, the Board does not agree with OPG's interpretation of the sections of O. Reg. 53/05 concerning acceptance of amounts in OPG's 2007 financial statements. OPG correctly pointed out that Section 6(2)5 of the regulation requires the Board to accept the net book values of OPG's fixed assets as set out in its 2007 audited financial statements. It also noted that those net book values include substantial amounts of unamortized ARC (as shown in Table 5-2 above). OPG then asserted: "According to O. Reg. 53/05, the OEB must accept into rate base OPG's prescribed fixed asset values."[48] The Board does not agree that OPG's conclusion follows from the requirements of Sections 6(2)5 or 6(2)6.

[48] OPG Argument-in-Chief, page 83.

Section 6(2)5 requires the Board to accept the amounts of certain items as set out in OPG's financial statements. In the Board's view, the purpose of this section was to limit the extent to which the Board and intervenors could go back in history and question the impact of OPG's past accounting decisions on amounts that were determined before the Board took over the responsibility for setting payment amounts. A requirement to accept certain amounts is not an instruction as to how the Board should use those amounts in determining OPG's revenue requirement. The Board notes that when it is intended that the Board ensure OPG recover certain amounts, O. Reg. 53/05 is explicit. For example, Section 6(2)4 obligates the Board to ensure OPG recovers nuclear refurbishment costs. In contrast, Sections 6(2)5 and 6(2)6 do not require the Board to ensure recovery of any amounts or to use certain methodologies, and do not circumscribe the Board's authority as set out in Section 6(1).

Third, the Board is not persuaded by OPG's argument that the reference to "return on rate base" in Section 6(2)7 on nuclear liability deferral accounts supports a conclusion that O. Reg. 53/05 obligates the Board to accept the rate base method for the cost of OPG's nuclear liabilities.

As more fully explained in section 5.3.3 of this decision on nuclear liability deferral accounts, the Board has concluded that the term "return on rate base" in Section 6(2)7 does not restrict in any way how the Board determines the revenue requirement impacts under Section 6(2)8. The Board's interpretation of Sections 5.1, 5.2, and 6(2)7 is that those sections require that OPG be "kept whole" when its nuclear liabilities increase in response to a new reference plan. However, contrary to OPG's interpretation, the Board finds that those sections do not specify how to calculate the amounts that would keep OPG whole.

The Board finds that O. Reg. 53/05 does not require the Board to use the rate base method when determining the revenue requirement impact for purposes of Section 6(2)8.

5.3.2 Recovering the cost of nuclear liabilities related to Pickering and Darlington

Having found that the Board is not required by O. Reg. 53/05 to accept OPG's use of the rate base method for the costs of nuclear liabilities, the Board considered the merits of various methods, including the rate base method, of recovering the costs.

In addition to OPG's rate base method, four other methods of determining the revenue requirement impact of the nuclear liabilities were discussed during the hearing. Those methods and OPG's rate base method are summarized in Table 5-5, which is based on calculations filed by OPG. The table deals only with the "return on rate base" aspects of each method. It omits depreciation of unamortized ARC and the other elements of the revenue requirement proposed by OPG that were not opposed by any party. Table 5-5 includes amounts for both the prescribed assets (Pickering and Darlington) and the Bruce stations. (The Board did not have all of the information required to separate the Bruce amounts from the amounts for Pickering and Darlington.) Cost of capital in the table is based on OPG's application (a capital structure of 42.5% debt, 57.5% equity; proposed debt rates of 5.65% in 2008 and 6.47% in 2009; and a return on equity of 10.5%).

In their arguments, some intervenors proposed new approaches or variations on the methods shown in Table 5-5.

Table 5-5: Comparison of Methods to Calculate the Revenue Requirement for Nuclear Liabilities

$ millions	OPG's Rate Base Method	CIBC Option 2	Flow-through Method	Method 3	Method 3(b)
Rate base	Average unamortized ARC ($2,325 million for 2008 and $2,178 million for 2009)	Rate base per OPG, less average unfunded nuclear liability ($1,231 million for 2008 and $878 million for 2009)	Zero	Same as OPG's rate base method	Same as CIBC Option 2
Revenue requirement	Cost of capital applied to rate base	Cost of capital applied to rate base. Revenue requirement also includes total forecast accretion expense and total forecast segregated fund earnings	Total forecast accretion expense, less total forecast segregated fund earnings	Cost of capital applied to rate base. Cost of debt is based on a blend of the OPG's average accretion rate of 5.6% (for the amount of the unfunded liability) and the forecast long-term debt rate (for the balance of deemed debt)	Cost of capital applied to rate base. The revenue requirement for the unfunded liability is based on OPG's average accretion rate of 5.6%
Cost of capital	$334.3	$180.9	-	$326.2	$179.3
Accretion expense	-	1,074.7	1,074.7	-	100.9
Segregated fund earnings	-	(888.1)	(888.1)	-	-
Revenue requirement	**$334.3**	**$367.5**	**$186.6**	**$326.2**	**$280.2**

Sources: Ex. J12.1, Attachment 1; Ex. H1-1-3, page 2; Ex. J7.1
Note 1: Amounts in the table relate to both the prescribed nuclear facilities and the Bruce stations.
Note 2: The amounts in the table are all taken from an OPG-prepared exhibit. The Board notes that the cost of capital amounts shown for CIBC Option 2 and Method 3(b) are different. Those amounts should be identical, however, given that the rate base for each method is the same. "CIBC Option 2" is contained in a report written in December 2004 by CIBC World Markets, commissioned by the government to assist it in determining the current payment amounts.

OPG noted that its total proposed revenue requirement for nuclear waste management and decommissioning costs (as shown in Table 5-4) would be less than the company's cash flow requirements during the test period (expected contributions to the segregated funds and nuclear costs funded through operations).

In addition to its argument that the regulation requires the Board to accept use of the rate base method (see section 5.3.1 above), OPG argued that the Board should approve the use of the method because it was used by the government when it set the current payment amounts in 2005, and it is the most appropriate methodology.

OPG referred to a December 2004 report from CIBC World Markets to support its contention that the rate base method was used to set current payment amounts. That report provided CIBC's analysis and advice on the initial regulated payment amounts for the prescribed assets. CIBC described two methods of dealing with nuclear liabilities. CIBC's preferred method, which it submitted followed traditional rate base methodology, involved recovering the unfunded liability through OPG's return on assets. CIBC acknowledged that this method "effectively requires rate payers to fund a higher cost of capital associated with the unfunded liability than the interest rate used in calculating the liability pursuant to ONFA."[49] This method is summarized in Table 5-5 under the heading "OPG's Rate Base Method".

CIBC also described an alternative method that involved removing the unfunded liability from rate base, which would lower OPG's return on capital, and collecting interest at the rate used under the ONFA to calculate the liability. This method is summarized in Table 5-5 under the heading "CIBC Option 2". According to CIBC, this method would have lowered the initial payment amounts by $1 per MWh.

OPG acknowledged that the various payments amounts discussed in the CIBC report are not the same as the payment amounts set by the government effective April 1, 2005. Part of the reason for the difference is that the payment amounts in the CIBC report were based on a 10 per cent return on equity while the government used a five per cent rate to set the initial payments. OPG's evidence was that the CIBC report and the initial rates were "entirely consistent in every regard, except for their recommendation on return on equity."[50] OPG concluded that the government must have used CIBC's preferred method, which OPG submitted is the same as its rate base method, to set the initial payments.

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[49] CIBC World Markets Inc., *Engagement Review of Financial Advisory Services on OPG's Initial Regulated Rate and Financial Soundness*, December 2004, page 19. [Exhibit L-2-10, Attachment 1]

[50] Transcript Volume 1, page 78.

OPG submitted that the rate base method is "the best and most appropriate method to recover OPG's nuclear waste management costs."[51] The CICA Handbook requires ARC to be included in the net book value of fixed assets and depreciated like any other element of asset cost. OPG considered that to be a rational allocation of the costs over the lives of the related assets. OPG also submitted that no investor would invest in nuclear generation if no consideration were given to the capital required to finance ARC.

OPG submitted that the rate base method is consistent with traditional regulatory practice in that it does not require "streaming" of particular costs to particular assets.

OPG noted that the revenue requirement that results from using the rate base method is not tied to the level or pace of cash contributions to the segregated funds or to fund earnings. An OPG witness submitted that:

> … we feel that any approach that involves nuclear fund earnings is going to result in volatility of regulatory earnings, as well as increased regulatory burden associated with scrutiny of those forecasts, and that earnings can be volatile is certainly illustrated by things that occurred in the early part of this year …[52]

CCC, CME (supported by AMPCO), SEC, and VECC objected to OPG's proposed rate base method. Other intervenors were silent on the issue.

There were three arguments against OPG's use of the rate base method that appeared in various forms in the written submissions of the intervenors. Those arguments are summarized below, followed by a description of the alternative approaches suggested by the intervenors.

First, intervenors argued that a rate base return on capital should be allowed only when capital has been supplied by debt or equity investors. Most intervenors who opposed OPG's use of the rate base method submitted that ARC is not funded by debt and equity and, therefore, none of that amount should attract a return equal to OPG's weighted average cost of capital (WACC). (CCC seemed to suggest that some amount

[51] OPG Argument-in-Chief, page 82.

[52] Transcript Volume 7, page 46. The event in the early part of the year referred to by the OPG witness was OPG's recognition of a loss of $51 million on the segregated funds in the first quarter of 2008, compared to earnings of $91 million in the first quarter of 2007.

of ARC should attract a return equal to WACC.) SEC's comment on funding of nuclear liabilities and ARC is typical:

> The use of rate base to calculate the amount of allowable debt (and therefore interest recovery), and the amount of allowed equity (and return on it), presupposes that this amount of capital is needed by the utility to operate. That is, the regulatory methodology used starts from the assumption that the utility needs to be capitalized by an amount equal to the rate base, through issuing either debt or equity. That assumption is only correct where the rate base involves real capital expenditures, actually incurred or needing to be funded.
>
> That is not true in the case of nuclear negative salvage. No money has been spent, and no capital has been raised through debt or equity.[53]

Second, intervenors noted there is no precedent in North America for the use of the rate base method for ARC, and this was acknowledged by OPG. Neither of the two owners of other nuclear generation facilities in Canada, Hydro-Québec and New Brunswick Power, are subject to cost-of-service regulation for nuclear output. With respect to rate regulated nuclear plants in the United States, OPG's expert on cost of capital provided her views on the impact of FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, which is virtually identical to CICA Handbook Section 3110. She indicated that "FASB 143 has not resulted in material changes in regulatory practice with respect to rate base or capital structure for U.S. utilities with ARCs and AROs."[54]

VECC noted that the U.S. Federal Energy Regulatory Commission (FERC) has not mandated a single method of dealing with recovery of asset retirement costs. VECC filed FERC Order No. 631, which deals with accounting and rate filing requirements for asset retirement obligations, and which states: "The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by the public utilities, licensees, and natural gas companies."[55]

Third, contrary to OPG's submission, the intervenors took the position that how the government treated ARC when it set the current payment amounts on April 1, 2005 is

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[53] SEC Argument, paragraphs 212 and 213.

[54] Addendum to Exhibit J1.3, page 4.

[55] Federal Energy Regulatory Commission, Docket No. RM02-7-000, Order No. 631, *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, April 9, 2003, paragraph 62. [Exhibit K11.7]

not relevant in this proceeding and not binding on the Board. CCC submitted that to imply the ratemaking treatment for 2008 and 2009 must be consistent with the 2005-2007 interim rates is tantamount to stating that the interim rates established a binding precedent.

SEC submitted that with respect to ARC, it is not clear what the government took into account when it set the initial payment amounts. SEC submitted that:

> [T]he Board is not in a position to look at how the Legislature's decision on nuclear negative salvage was made, the evidence the Legislature considered, or whether the specific circumstances of that decision are different from the current situation.[56]

SEC argued that the government's earlier decision should not influence the Board's consideration of the issue in this case.

Intervenors recommended alternative approaches to setting the revenue requirement.

CCC agreed that ARC should be included in rate base and that depreciation of that amount should be an allowable cost. CCC submitted, however, that the Board should distinguish between the funded and unfunded components of ARC in awarding a return on rate base. CCC proposed that the unfunded part of rate base would equal the average unfunded nuclear liabilities during the test period. It was not clear how CCC would calculate unfunded liabilities. CCC's argument referred to an OPG exhibit that showed the forecast average unfunded nuclear liabilities are $1,231 million for the last nine months of 2008 and $878 million for 2009. Another part of the CCC argument, however, suggests that unfunded liabilities equal annual average ARC minus average annual fund contributions.[57]

CCC submitted that the shareholder should only earn a return on capital raised to date and that customers should not pay for a return on capital that has not been raised. CCC likened unfunded nuclear liabilities to deferred income taxes and submitted that there should be a zero rate of return on the unfunded part of rate base.

CCC argued that the calculation of the unfunded portion of rate base would not represent an administrative burden and OPG has overstated the ratemaking difficulties.

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[56] SEC Argument, paragraph 177.

[57] CCC Argument, paragraph 111.

CCC claimed that customers would be willing to accept the risk that the unfunded portion of rate base may fluctuate due to conditions in the investment markets in order to defer the cost of funding to future test years when the funds have been raised.

CME recommended including ARC in rate base for the limited purpose of determining depreciation, which CME would allow as a recoverable expense. It argued for excluding ARC from the capital structure for the purposes of determining OPG's cost of debt and equity capital. CME recommended that the Board adopt a method CME called "Cost of Service Supplement to ARC Depreciation." Under this approach, OPG would be permitted to recover "the estimated annual amount needed, over and above the ARC depreciation amount, to produce, at the end of the economic life of the nuclear assets, the portion of the fund needed to retire and decommission the assets which will not be funded by ARC depreciation and interest accruals thereon."[58] CME's argument contained calculations to illustrate how its proposed method might work.

CME proposed, as a surrogate for its recommended approach, that OPG be permitted to recover 4.6% per annum on the unamortized balance of ARC included in rate base during the test period.[59] CME asserted that the combination of ARC depreciation and this 4.6% return would "be more than sufficient to produce, at the end of the economic life of the nuclear assets, the unfunded portion of the total undiscounted liability which gave rise to ARC."[60] CME also urged the Board to characterize its determination on these issues as interim only. It recommended that the Board sponsor, before OPG's next application, a consultation on the regulatory treatment of nuclear decommissioning costs, a process that could consider the results of the National Energy Board's ongoing assessment of retirement costs with respect to abandonment of pipelines.[61]

AMPCO supported CME's recommended approach, and also advocated that the Board undertake further review of the ratemaking treatment of ARC.

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[58] CME Argument, paragraph 91.

[59] CME refers to 4.6% as the "prevailing discount rate." [CME Argument, paragraph 113] The Board understands, however, that only a portion of the $10.8 billion ARO liability at December 31, 2007 (being the $1,386 million increase that was booked at the end of 2006) has been calculated using a 4.6% discount rate; the balance of the ARO liability has been measured using a 5.75% discount rate.

[60] CME Argument, paragraph 97.

[61] See National Energy Board Discussion Paper, *Land Matters Consultation Initiative, Stream 3: Financial Issues Related to Pipeline Abandonment*, March 2008.

SEC submitted that the Board has insufficient evidence to determine whether OPG's rate base method produces a just and reasonable result. SEC urged the Board to accept an adjusted rate base method for making its first order under Section 78.1 and to order a more detailed review of the regulatory treatment of nuclear liabilities before OPG's next application. SEC recommended that the Board accept the amount of depreciation expense proposed by OPG for the test period but that it not award the return on unamortized ARC that was proposed by OPG. Instead, SEC recommended that the Board allow a return of 4.6% on average unamortized ARC in rate base.[62]

VECC supported granting a return on unamortized ARC that is lower than the weighted average cost of capital. It advocated a sinking fund approach to recovery of nuclear liability costs, an approach that was not set out in detail in VECC's argument. VECC said one way to implement its sinking fund method would be to adopt the treatment recommended by CME. VECC did not comment on whether OPG should be allowed to recover depreciation of ARC.

By recommending that the Board isolate a portion of rate base and attribute a different return to that component, the intervenors support "streaming" of costs to the particular assets, a practice opposed by OPG. CCC, CME and VECC submitted that the Board has the discretion to determine the cost of capital to be applied to any element of rate base, a position also taken by Board staff. VECC submitted that the two Board decisions cited by OPG as precedents for not streaming financing costs are not relevant because they involved relatively small amounts of rate base and because "streaming" was not at issue in the cases.[63]

In its reply argument, OPG stated that most of CME's assumptions, claimed facts and calculations in respect of CME's proposed method had not been put into evidence or tested in the hearing, and that many of them were wrong. OPG submitted that the Board should disregard CME's new calculations of the revenue requirement.

OPG disagreed with the intervenors that cited the normal regulatory practice of awarding no return on deferred tax balances as support for their recommendation that

[62] SEC described its proposed 4.6% rate as "the discount rate used to discount the future liabilities to the present." [SEC Argument, paragraph 214] As noted in footnote 12, only a portion of the current ARO liability (being the $1,386 million increase that was booked at the end of 2006) has been calculated using a 4.6% discount rate. A higher discount rate applies to the balance of the ARO liability.

[63] VECC Argument, paragraph 38. The two Board decisions cited by OPG, in the addendum to Exhibit J1.3, were: Toronto Hydro (EB-2007-0680) and Centra Gas (EBRO 474).

there be no return on unamortized ARC. OPG pointed out that deferred taxes are considered to be a form of no cost capital because customers have already prepaid taxes through rates. That is not the case for OPG's nuclear liabilities.

OPG opposed the interim treatment advocated by the intervenors. In OPG's view, its proposal on nuclear waste management and decommissioning costs has been clear since the start of this proceeding. Intervenors have had the opportunity to gather evidence through the Technical Conference, interrogatories and cross-examination of OPG witnesses. OPG also asserted that deferring a final decision on the method of recovering the costs would result in a significant risk for OPG, and would require further consideration of the cost of capital when the final nuclear waste methodology is determined.

Board Findings

In the Board's view, there is no doubt that the cost of nuclear liabilities should be included in the revenue requirement for the prescribed facilities. Managing nuclear waste, and decommissioning the plants at the end of their lives, is an integral part of operating the Pickering and Darlington plants. The issue is not whether such costs should be recovered by OPG but, rather, how those costs should be measured for ratemaking purposes.

As noted by OPG and intervenors, there does not appear to be any consistent and generally accepted treatment of AROs and ARCs in other North American jurisdictions. The standards governing the financial accounting for AROs are relatively new. The FASB in the United States issued Statement No. 143 in 2001, and the CICA Handbook section 3110 in 2003. Whether North American regulators will ultimately modify their ratemaking approaches to be compatible with the accounting standards is not clear.

Given the newness of the financial accounting standards for AROs, and the apparent lack of any consensus among regulators about whether to accept a rate base that includes ARC, the Board is not prepared to accept use of the rate base method in precisely the form proposed by OPG.

The Board will accept inclusion in the revenue requirement of depreciation expense for the nuclear plants computed in accordance with GAAP, as proposed by OPG. Under GAAP, ARC included in the net book value of fixed assets is depreciated like any other fixed asset cost. It appears as an expense in OPG's income statement. The Board finds that this approach results in a rational allocation of cost. Several intervenors explicitly supported that approach and no intervenor objected to it.

The more difficult issue is whether OPG should be permitted to recover its cost of capital on a rate base that includes 100% of unamortized ARC. There was no evidence provided at this hearing that any regulator has yet permitted the inclusion of ARC in rate base. Indeed, the policies of FERC in the United States specifically require that:

> … all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment. If the public utility, licensee or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates.[64]

Under accounting standards that existed before the release of FASB Statement No. 143 and CICA Handbook Section 3110, it was reasonable to conclude that the original cost of fixed assets on a regulated entity's balance sheet had been financed by investor-supplied debt and equity funds. While that remains true for many regulated entities, it clearly is no longer true for entities that have booked AROs.

When OPG increased its nuclear liabilities by $1,386 million at the end of 2006, and increased its fixed asset book values by the same amount, it did not have to arrange a debt or equity issue, or invest some of its retained earnings. All that happened was that OPG posted a journal entry to its general ledger – it debited fixed assets for $1,386 million and credited nuclear liabilities for the same amount.

At some point, the unamortized ARC that is included in fixed assets in effect will be funded by debt or equity because OPG is obligated by ONFA to make cash contributions to the segregated funds; however, until those contributions occur, the ARC component of fixed assets has not been funded with capital supplied by investors.

It would be inappropriate, in the Board's view, to award OPG a rate base-type return on unamortized ARC when OPG has not had to raise the full amount of ARC as new debt or equity. In the Board's view, the rate base method over-compensates OPG when OPG's nuclear liabilities are not fully funded. As CIBC noted in its December 2004 report, the rate base method "effectively requires ratepayers to fund a higher cost of

[64] FERC Order No. 631, paragraph 62.

capital associated with the unfunded liability than the interest rate used in calculating the liability pursuant to ONFA."[65]

The Board finds that OPG should use a variation of Method 3(b) shown in Table 5-5. The Board will accept the rate base for the prescribed nuclear assets as proposed by OPG. Rate base shall be calculated using average annual fixed asset balances that are determined in accordance with GAAP. Those fixed asset balances include unamortized ARC. The return on rate base, however, will not be as proposed by OPG.

The Board will require that the return on a portion of the rate base be limited to the average accretion rate on OPG's nuclear liabilities, which is currently 5.6%. That portion of rate base that attracts that return will be equal to the lesser of: (i) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. When the average unfunded nuclear liabilities exceed the amount of unamortized ARC in fixed assets, then the portion of rate base that attracts the 5.6% return would be capped at the average amount of unamortized ARC; if the average unfunded liabilities are forecast to be lower than the average unamortized ARC, it is appropriate to limit the portion of rate base that attracts the 5.6% return to the unfunded amount. That approach recognizes that OPG has raised debt (or used its retained earnings) to fund part of the unamortized ARC.

For the balance of the rate base, the return on capital should be calculated using the capital structure, debt rate, and return on equity approved by the Board in Chapter 8 of this decision.

The Board has some, but not all, of the information required to calculate the portion of rate base that will attract the 5.6% return. OPG's evidence includes the forecast amounts of average unamortized ARC in the Pickering and Darlington fixed assets ($1,227 million for 2008 and $1,121 for 2009). Its evidence, however, did not include the forecast unfunded liability in respect of Pickering and Darlington (the evidence provided by OPG showed a combined unfunded amount that included amounts related to the Bruce stations). OPG should provide the amounts of forecast average unfunded liabilities related to Pickering and Darlington as part of the information supporting the draft payment order based on this decision.

[65] CIBC Report, page 19.

The Board notes that the method it will require OPG to use to set payment amounts yields much the same result as Option 2 proposed by CIBC in its December 2004 report (Option 2). The CIBC report described the Option 2 calculation as follows: "Remove the unfunded liability from rate base, and instead collect interest as calculated per ONFA on the unfunded liability explicitly in rates."[66]

The Board agrees with those intervenors who submitted that the cost of capital impact should be based only on amounts of "funded ARC." The Board did not accept, however, the specific methods advocated by the intervenors.

The Board disagrees with CCC's submission that OPG should earn no return on unfunded amounts. Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its nuclear liabilities whether they are funded or not.

CME advocated its "Cost of Service Supplement to ARC Depreciation" concept as a model the Board should consider in the future, while VECC advanced a sinking fund method as the right approach. Neither model was fully developed in the intervenor arguments. It appeared to the Board that both models would require the Board to develop an alternative funding schedule in order to calculate the revenue requirement. The Board questions the utility and practicality of developing alternatives to the funding schedule set out in the ONFA.

The Board does not adopt the recommendation from intervenors that the Board's decision on this issue should be labelled as "interim" or that the Board should launch a consultation process on the ratemaking aspects of asset retirement obligations. The Board agrees with OPG that there was ample opportunity in this proceeding for all parties to explore the issues and alternative treatments. The Board believes the right forum for dealing with this issue is a hearing on an application from OPG. To the Board's knowledge, no other entity it regulates has recorded any material amounts of AROs. For OPG, the issue is both real and material.

[66] CIBC Report, page 19. The calculations provided by OPG at the hearing and summarized in Table 5-5 indicate a different interpretation of Option 2. The calculation of the revenue requirement in Table 5-5 includes forecast accretion expense on OPG's entire nuclear liability (which was $10.8 billion at the end of 2007), net of forecast earnings on the segregated funds. By including amounts related to funded liabilities, that calculation appears to be in conflict with the description of the Option 2 calculation in the CIBC report, which refers to unfunded liabilities only.

Before the hearing on OPG's next payment amounts application is completed, the National Energy Board, Provincial regulatory bodies, FERC, or other bodies may issue position or policy papers or release decisions dealing with AROs. If such external developments occur, OPG, intervenors, and Board staff will have the opportunity in that hearing to submit evidence and argue for a different approach to AROs.

5.3.3 Section 5.1 and 5.2 deferral accounts

O. Reg. 53/05 was amended in 2007 to require OPG to establish a deferral account to capture certain amounts related to changes in nuclear liabilities that occurred after April 1, 2005 and before the effective date of the Board's first order (Section 5.1), and after the date of the Board's first order (Section 5.2). O. Reg. 53/05 states:

> **Nuclear liability deferral account, transition**
>
> **5.1** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.
>
> (2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually.
>
> **Nuclear liability deferral account**
>
> **5.2** (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,
>
> (a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and
>
> (b) the liability arising from the current approved reference plan.
>
> (2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct.

On December 31, 2006 OPG recorded an increase of $1,386 million in its nuclear decommissioning and nuclear waste management liabilities. In accordance with Canadian GAAP, the increase in the nuclear liabilities was added to the net book value of the relevant nuclear stations. The net book value of the Bruce stations was increased by $878 million (to $1,271 million at the end of 2006), and the net book value of the Pickering and Darlington stations was increased by $508 million (to $2,454 million at the end of 2006).[67]

OPG's 2006 financial statements described the basis for the change in the liabilities and the impact the change would have on OPG's future financial results:

> The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. As at December 31, 2006, OPG updated the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities. The resulting updated Reference Plan ("2006 Approved Reference Plan") was approved by the Province in accordance with the terms of the ONFA [Ontario Nuclear Funds agreement]. The increase in cost estimates reflected in the Approved Reference Plan is mainly due to additional used fuel and waste quantities resulting from station life extension, recent experience in decommissioning reactors, and changes in economic indices. The increase is partially offset by the deferral of some station decommissioning dates.
>
> As a result of the new Reference Plan, OPG will recognize additional expenses including accretion on the fixed asset removal and waste management liabilities and depreciation of the carrying value of the related fixed assets. The impact of these additional expenses will be reduced by the recognition of a regulatory asset to be recovered through future prices charged to customers, as prescribed by the amended regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) …[68]

The balance in the Section 5.1 nuclear liability deferral account as at December 21, 2007 was $130.5 million. The components of that balance are shown in Table 5-6. OPG's pre-filed evidence included the components shown in the total column but did not include a breakdown by facility. The figures in the Pickering/Darlington and Bruce columns in Table 5-6 are estimates based on the oral testimony of an OPG witness.

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[67] Exhibit J1.5; Exhibit B1-1-1, Table 2; and Exhibit G2-2-1, Table 2.

[68] OPG 2006 consolidated financial statements, Note 9.

Table 5-6: Nuclear Liability Deferral Account, December 31, 2007

$ millions	Pickering/ Darlington	Bruce	Total
Return on rate base	$ 27.0	$ 48.5	$ 75.4
Depreciation	44.7	9.0	53.7
Capital tax	*n/a*	*n/a*	3.1
Fuel expense	*n/a*	*n/a*	(5.2)
Interest (6%)	*n/a*	*n/a*	3.5
Total	**$ 76.5**	**$ 54.0**	**$ 130.5**

Sources: Ex. J1-1-1, page 12, and Transcript Vol. 15, page 86.

n/a - Not available

Section 6(2)7 of O. Reg. 53/05 sets out the maximum recovery period and provides a list of items on which the account balance is to be based:

> 7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,
>
> i. return on rate base,
>
> ii. depreciation expense,
>
> iii. income and capital taxes, and
>
> iv. fuel expense.

OPG has used the rate base method to determine the balance of this deferral account. The "return on rate base" included in the Section 5.1 deferral account was based on the average 2007 balance of the incremental ARC added to the net book value of fixed assets as a result of the increased nuclear liability ($1,359 million), multiplied by a 5.55% return on rate base. The 5.55% return was based on a capital structure of 55% debt and 45% equity, an interest rate of 6%, and a return on equity of 5%. OPG indicated that the capital structure and rates are the same as those used by the Province to set the initial payment amounts.

Submissions from OPG and intervenors on using the rate base method for the Section 5.1 and 5.2 deferral accounts were essentially the same as their arguments in support of, or in opposition to, using the rate base method for the prescribed assets for the test period (see section 5.3.2 above).

As noted in the preceding section of this decision, OPG submitted that the reference in Section 6(2)7 to "return on rate base" shows that the government intended OPG to use the rate base method to calculate balances in the Section 5.1 and 5.2 deferral accounts. OPG argued that:

> There would be absolutely no need for, or even meaning to, this provision if it had not been the LGIC's [Lieutenant Governor in Council] intention that payment amounts reflect the revenue requirement impact of the rate base approach to recovering the cost of OPG's nuclear waste management obligations.[69]

Board staff submitted that Section 6(2)7 of the regulation requires the Board to accept the amounts in the Section 5.1 deferral account.

CME disagreed with the staff position because it "implies that the Board cannot assess the appropriateness of the method OPG has used to calculate the amount of the revenue requirement impact to be recorded in the Deferral Account."[70] In CME's view, the phrase "to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded" in Section 6(2)7 means that the account balance must be determined in accordance with a method that the Board has determined is appropriate.

CME argued that no amounts related to the increase in the Bruce nuclear liabilities should be included in the Section 5.1 deferral account.

SEC's submissions on the nuclear deferral accounts related mainly to the Section 5.2 account, which relates to changes in nuclear liabilities that occur after the date of the Board's first order. As noted in section 5.3.1 above, SEC concluded that the references to "return on rate base" and the other three items in Section 6(2)7 of the regulation are problematic because OPG's audited financial statements either do not contain such items or because a literal interpretation of the item leads to an absurd result. SEC submitted that an appropriate interpretation of "return on rate base" as it relates to the

[69] OPG Argument-in-Chief, page 84.

[70] CME Argument, paragraph 42.

Section 5.2 deferral account is that it is intended to require OPG to record an amount reflective of the time value of money.

Board Findings

The two issues with respect to the nuclear liability deferral accounts are: (i) Does the regulation require OPG to use the rate base method to calculate the balances in the accounts?, and (ii) Are the deferral accounts solely to record costs of nuclear liabilities of the prescribed facilities, or should costs related to the Bruce stations also be included? Reaching answers to these questions required the Board to interpret the meaning of the term “return on rate base” in Section 6(2)7.

OPG’s position is that the inclusion of the term “return on rate base” in Section 6(2)7 means the LGIC must have intended that OPG use, and the Board adopt, the rate base method. The Board does not agree with OPG’s position.

On the surface, the instructions in Section 6(2)7 seem to make no sense. The section contemplates that the amount of “return on rate base” and the amounts of other items listed in the section are the amounts “as reflected in” OPG’s December 31, 2007 financial statements. As SEC points out, there is no item “return on rate base” in OPG’s financial statements. Thus, a literal interpretation of Section 6(2)7 would lead to no recovery whatsoever for amounts in the Section 5.1 deferral account that OPG labels as “return on rate base”.

Another difficultly in interpreting Section 6(2)7’s reference to “return on rate base” is that, by definition, the additional ARC that arises when a nuclear liability is increased is not included in rate base at the time the ARC is recorded. If it were in rate base at that time, a deferral account would be unnecessary. The additional ARC will not be included in rate base until the Board resets the payment amounts in a subsequent hearing. Once again, a literal application of the “return on rate base’ in Section 6(2)7 would lead to a zero return for OPG because there would be no amount in rate base on which a return could be calculated.

The Board has adopted an approach to Section 6(2)7 that is consistent with the purpose of the Section 5.1 and 5.2 deferral accounts. In the Board’s view, the purpose of those accounts is to capture revenue requirement impacts of certain events that occur after payment amounts for OPG have been set. The Section 5.1 account was for nuclear liability increases that occurred after the effective date of the payment amounts set by the Province but before the effective date of the Board's first order. Section 5.2 is for liability changes that occur after the Board has set payment amounts for a particular period. It is reasonable to conclude that the intent of the deferral accounts is to ensure OPG is "kept whole" for the cost consequences of liability increases that were not, and could not have been, considered when payment amounts were set.

In the Board's view, the accounts should operate to ensure OPG is in no worse, or better, a financial position than it would have been had the Province (in the case of the Section 5.1 account) or the Board (in the case of the Section 5.2 account) been aware of the future increase in the liabilities at the time it set the payment amounts. Had there been knowledge of a pending increase in the nuclear liabilities, presumably the approved revenue requirement would have included some additional revenue to offset the known costs of liability increases that were going to happen during the test period.

Having concluded that the intent of O. Reg. 53/05 with respect to the deferral accounts was to ensure OPG is "kept whole," the Board also concluded that Section 6(2)7 does not specify any particular method for calculating the amounts that would keep OPG whole. In the Board's view, the method that should be used to determine balances in the deferral accounts should be the same as the method used by the Board (or for the initial period, the Province) to include the cost of nuclear liabilities built into the existing payment amounts.

Under this interpretation of Section 6(2)7, what does the phrase "as reflected in the audited financial statements" mean as it relates to "return on rate base"? In the Board's view, that phrase means that, in respect of new liabilities, OPG should be allowed to record in the deferral account the "return" that it is inherent in the existing payment amounts that are recognized as revenue in OPG's financial statements.

To assess the appropriateness of the balance in the Section 5.1 deferral account, it is necessary determine how the cost of nuclear liabilities was included in the initial payment amounts. OPG's evidence was that those payment amounts were determined by the Province using: the rate base method for both the prescribed assets and the Bruce stations; a 55% debt-45% equity capital structure; a debt rate of 6%; and, a return on equity of 5%.

As SEC pointed out, it is not entirely clear how the initial payment amounts were set by the Province. Based on the evidence in this proceeding, except for the inclusion of the

Bruce stations, the Board accepts that the Province used the approach described by OPG. In Chapter 6 of this decision, the Board concludes that the record is less clear as to whether the Province adopted the rate base method for the Bruce nuclear liabilities when it set the initial payments.

Notwithstanding the lack of clarity about how the Bruce stations were handled in the initial payment amounts, the Board approves the balance in the Section 5.1 deferral account, including the accrual of a 5.55% return on the incremental unamortized ARC related to Pickering, Darlington and Bruce nuclear stations. The Board notes that 63% of the increase in nuclear liabilities that occurred at the end of 2006 related to the Bruce stations. That increase occurred before the amendment of O. Reg. 53/05 to add Section 5.1, so the government presumably would have been aware of the magnitude of the increase in the Bruce liabilities. If the government intended to restrict the Section 5.1 deferral account to just Pickering and Darlington, and exclude the substantial increase in the Bruce liabilities, the regulation would have stated that.

As for the Section 5.2 deferral account, the Board is taking a different approach. First, the account should be restricted to the revenue requirement impact of changes in the nuclear liabilities for Pickering and Darlington. As discussed in Chapter 6, the Board has concluded that the terms “revenue requirement” and “return on rate base” are not applicable to OPG’s unregulated Bruce activities. Second, the “return on rate base” component should be calculated in accordance with the method outlined in section 5.3.2 of this decision concerning the calculation of the revenue requirement impact of nuclear liabilities for the test period. This is consistent with the Board’s interpretation of the regulation that the deferral accounts are intended to keep OPG whole and that entries to the account should be made using the same regulatory structure as was used to set the payment amounts. The practical consequence of this approach is that the “return on rate base” element of the Section 5.2 deferral account will be determined using the discount rate that OPG used to calculate the new increased liabilities until such time as OPG begins to fund the additional liability.

6 BRUCE NUCLEAR STATIONS: OPG's REVENUES AND COSTS

OPG owns the Bruce A and Bruce B nuclear generating stations located on the shore of Lake Huron near Kincardine, Ontario. Currently, six units are operational and the two other units are being refurbished. When all eight units are operational, the aggregate capacity of the stations will be over 6,200 MW.

In 2001, OPG leased the stations to Bruce Power L.P., a partnership not related to OPG.[71] The lease runs until 2018 and Bruce Power has an option to renew the lease for a further 25 years. Bruce Power operates the stations and supplies energy to the IESO-administered electricity market.

OPG receives lease payments from Bruce Power as well as revenues for providing engineering and other services to the partnership. OPG retained responsibility for the decommissioning and nuclear waste management liabilities related to Bruce A and Bruce B.

The Bruce nuclear generating stations are not prescribed generation facilities under O. Reg. 53/05. Bruce Power holds a generation license issued by the Board. The Board, however, has no authority to set or review the terms of the lease between OPG and Bruce Power and it does not regulate the prices for engineering and other services provided to Bruce Power by OPG.

Despite the fact that the Bruce nuclear stations are not prescribed generation facilities, OPG's revenues and costs related to the Bruce lease were major issues in this proceeding.

O. Reg. 53/05 requires the Board to include OPG's revenues and costs for Bruce in the determination of the payment amounts for the Pickering and Darlington nuclear stations. OPG forecast net Bruce revenues for the test period of $134.4 million, which OPG deducted from the nuclear revenue requirement to determine the payment amounts for Pickering and Darlington. This chapter addresses the question of whether OPG has

[71] Bruce Power L.P. is a partnership among Cameco Corporation, TransCanada Corporation, BPC Generation Infrastructure Trust, a trust established by the Ontario Municipal Employees Retirement System, the Power Workers' Union and The Society of Energy Professionals.

used an appropriate method to calculate the revenues and costs for the test period for Bruce.

OPG proposed to include certain 2007 costs related to the Bruce nuclear liabilities in the deferral account established by Section 5.1 of the regulation. That issue is addressed in Chapter 5 of this decision.

Paragraphs 9 and 10 of Section 6(2) of O. Reg. 53/05 state:

> 9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.
>
> 10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2 [Pickering A, Pickering B, and Darlington].

OPG proposed that the test period revenue requirement for Pickering A, Pickering B and Darlington be reduced by approximately $134 million in respect of net revenues related to Bruce. OPG's forecast test period revenues and costs for the Bruce stations are shown in Table 6-1, together with actual 2007 amounts calculated on a comparable basis.

Some of the forecast revenues and costs included in OPG's application in respect of Bruce were determined in accordance with Canadian GAAP applicable to a non-regulated entity. OPG calculated certain other costs and revenues using other accounting bases. The significant non-GAAP policies used by OPG were:

- OPG used a cash basis of accounting for revenue from the Bruce lease. Had OPG computed the revenue in accordance with GAAP, the lease revenue for the test period would have been approximately $30 million more than shown in OPG's application.
- OPG's calculation of the net revenues related to Bruce omits both the accretion expense on the fixed asset removal and nuclear waste management liabilities related to the Bruce stations and the earnings on the related segregated funds.

Table 6-1: OPG's Calculation of Excess Bruce Revenues

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenue:			
Lease with Bruce Power	$ 252.8	$ 257.4	$ 263.2
Services revenue	48.1	19.7	12.6
Total revenue	**300.9**	**277.1**	**275.8**
Costs:			
Depreciation	120.6	77.5	66.7
Property tax	13.8	15.2	15.5
Capital tax	2.8	2.6	2.5
Used fuel storage and management	13.3	14.1	14.8
Interest	37.6	28.4	27.6
Income tax	-	-	-
Return on equity	27.7	70.2	66.1
Total costs	**215.8**	**208.0**	**193.2**
Revenue less costs	**$ 85.1**	**$ 69.1**	**$ 82.6**
9/12's of 2008 net revenue			51.8
Offset to test period revenue requirement			**$ 134.4**

Sources: Ex. G2-2-1, Tables 1 and 3; Ex. K1-1-1, Tables 1 and 2.

- OPG has proposed to use the same "rate base method" to calculate the cost of the Bruce nuclear liabilities as it proposed to use for the nuclear liabilities of the prescribed facilities. Under that approach, the net book value of OPG's fixed assets related to the Bruce stations was considered to be part of the rate base on which OPG calculated a return on capital. Table 6-1 shows that OPG has included a return on equity as a cost of the Bruce lease. That cost would not be included in an income statement prepared in accordance with GAAP. The return was calculated using the same deemed capital structure (42.5% debt and 57.5% equity) and 10.5% ROE that were proposed by OPG for the prescribed facilities.
- The interest expense in Table 6-1 has also been calculated using the rate base method, which results in the inclusion of deemed interest expense, which is greater than the amount that would be recorded under GAAP.
- OPG's calculation of costs does not include any income tax provision.

The GAAP approach to calculating OPG's revenues less costs for the Bruce stations would result in a substantially higher net revenue amount than would OPG's proposed approach. The pre-tax amounts determined under the two different approaches are reconciled in Table 6-2.

Table 6-2: Bruce Revenues and Costs: Reconciliation of OPG's Calculation with GAAP

$ millions	2007 Actual	2008 Plan	2009 Plan
Revenues less costs per OPG (Table 6-1)	**$ 85.1**	**$ 69.1**	**$ 82.6**
Add:			
Adjust lease revenue to accrual accounting	20.7	20.7	15.5
Eliminate deemed interest expense	37.6	28.4	27.6
Eliminate return on equity	27.7	70.2	66.1
Eliminate deemed capital taxes	2.8	2.6	2.5
Expenses recorded in nuclear deferral account	3.5	-	-
Earnings on segregated funds	194.2	234.9	262.0
Deduct:			
Accretion on nuclear liabilities	(207.2)	(255.9)	(282.0)
Interest on actual debt	(20.3)	(21.2)	(21.1)
Actual capital taxes	(1.1)	(4.4)	(3.6)
GAAP income before tax	**$ 143.0**	**$ 144.4**	**$ 149.6**

Source: Ex. J8.1, page 6.

OPG noted that Section 6(2)9 of O. Reg. 53/05 requires the Board to ensure OPG recovers "all the costs it incurs" with respect to the Bruce stations. OPG argued that it is clear that a return on equity in respect of OPG's investment in the Bruce stations is a cost incurred by OPG. OPG submitted that Section 6(2)8 of the regulation, which requires the Board to ensure OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan, is not restricted to nuclear liabilities related to the prescribed facilities. Rather, OPG contends that Section 6(2)8 is of general application and must be applicable to the Bruce liabilities because those liabilities arise from OPG's approved reference plan under ONFA. OPG submitted: "Nothing about the legislative purpose of O. Reg. 53/05 demands excluding Bruce nuclear waste and decommissioning liabilities from the determination of OPG's revenue requirement."[72]

[72] OPG Reply Argument, page 115.

OPG claimed that its proposed treatment of Bruce lease costs, including the use of the rate base method, is the same as that recommended by CIBC World Markets in its December 2004 report (the "CIBC report"). That report stated:

> Based on CIBC World Markets' analysis and the objectives of the Province previously stated, we believe that the revenues from the Bruce lease, net of OPG's costs for these assets, should be included as part of the regulated rate base, which has the effect of lowering the regulated rate for OPG's nuclear assets.[73]

OPG also claimed that its proposed treatment is the same as the treatment used by the Province to set the existing payment amounts. OPG submitted that the policy issue of how much of the Bruce lease revenues the government intended to be used to offset the revenue requirement for Pickering and Darlington is made clear from the government's decision to include the Bruce fixed assets in OPG's rate base during the interim period. OPG argued that this interim period treatment is "strong evidence that the cost arising from the 'rate base' approach to recovering nuclear waste management was intended to qualify under Section 6(2)9 of O. Reg. 53/05 as a 'cost' which OPG 'incurs' with respect to the Bruce stations."[74]

OPG also provided its opinion on what the Province knew, and what the Province assumed, when it set the current payment amounts:

> …it was well known to the Province that the interim rates that it approved for the 2005 to 2008 period reflected costs associated with Bruce A and B nuclear liabilities. Not only did the province assume that "costs incurred" with respect to the Bruce facilities included nuclear liabilities associated with the Bruce facilities, it also assumed, for purposes of interim rates, that the proxy for the recovery of that cost was the return on the value of the Bruce NGS fixed asset, i.e., the "rate base method." … [T]he fact that interim rates employed the rate base method for the recovery of nuclear liability costs and the fact that the Province was aware, before the application was made, of what OPG was seeking in this case, while not binding on the OEB after April 1, 2008, are powerful evidence of surrounding circumstances, which must be considered in determining the meaning and intent of sections 6 (2) 7 to 10 of the Regulation.[75]

OPG asserted that "common sense" and "common regulatory practice" support a conclusion that return on equity is a "cost" under Section 6(2)9 of the regulation.

[73] CIBC Report, page 20.

[74] OPG Argument-in-Chief, page 87.

[75] OPG Reply Argument, pages 113 and 114.

Board staff took the position that Section 6(2)8 of the regulation, which deals with recovery of the revenue requirement impact of OPG's nuclear liabilities, is applicable only to the cost of the nuclear liabilities related to the prescribed nuclear facilities, Pickering and Darlington. Board staff submitted that the relevant sections of the regulation with respect to the OPG's test period costs for Bruce are Sections 6(2)9 and 6(2)5. Staff submitted that it is appropriate for the Board to determine the Bruce costs incurred and revenues earned by OPG in the test period:

> … by giving those terms ("cost" and "revenues") the meaning they would ordinarily have in the context of rate-setting applications (including those based on a cost-of-service application). In other words, the Board should use generally accepted accounting principles applicable in a rate setting environment to determine what constitutes a cost with respect to Bruce Facilities.[76]

CCC submitted that the Board should exclude a return on Bruce assets when calculating costs recoverable under Section 6(2)9 of the regulation. CCC contended that O. Reg. 53/05 does not guarantee OPG a return on the Bruce assets.

CME argued that the only reasonable interpretation of Sections 6(2)9 and 6(2)10 of the regulation is that "nuclear liability costs attributable to Bruce are only recoverable to the extent that Bruce costs exceed Bruce revenues."[77] CME argued that the total amount of the "rate base method" elements of OPG's calculation of Bruce costs – deemed interest expense, return on equity, and deemed capital taxes – should not be recovered. CME calculated that by including those items as costs, OPG has understated the excess of its Bruce revenues over costs for the test period by $171 million.

CME submitted that whether the word "costs" in Sections 6(2)9 and 6(2)10 should be construed to include a return on Bruce assets is a question for the Board to resolve. In CME's view, the Board is not bound by the method used to set initial rates. CME contended that there is nothing in the regulation that supports OPG's contention that "costs" must include a profit or return. It also submitted that OPG's interpretation of the regulation would result in OPG earning a guaranteed return on its Bruce investment, a result CME argued was not intended by O. Reg. 53/05.

VECC adopted CME's submission on the proper interpretation of the regulation with respect to the Bruce assets.

[76] Board Staff Argument, page 10.

[77] CME Argument, page 16.

In its reply, OPG stated that CME, VECC and Board staff argued that "OPG has no right to any recovery of the cost of nuclear liabilities, however calculated, with respect to the Bruce facilities."[78] OPG submitted that those arguments are based on a "profoundly and patently unreasonable misinterpretation of the Regulation which, if adopted, would constitute grounds for reversal on a matter of law".[79]

OPG objected to CME's submission that nuclear liability costs for the Bruce stations are only recoverable to the extent that Bruce costs exceed Bruce revenues. OPG submitted that Sections 6(2)9 and 6(2)10 "can only be read to mean that any credit to the revenue requirement arising from the Bruce facilities is after recovery of *all costs incurred* with respect to those facilities."[80] (emphasis in original)

Board Findings

The Board agrees with OPG that O. Reg. 53/05 requires the Board to ensure that OPG recovers all of its costs with respect to Bruce. The language in Section 6(2)9 ("all the costs it incurs") is clear and unambiguous.

The Board also finds that costs related to the Bruce nuclear liabilities are costs for the purposes of Sections 6(2)9 and 6(2)10. As owner of the Bruce stations, OPG has the obligation to manage nuclear waste and to decommission the plants, and that obligation gives rise to substantial costs. Although there are different views about how those costs should be measured, there was no evidence in this proceeding that OPG will not be incurring costs during the test period in respect to the Bruce nuclear liabilities.

The Board also finds that any reduction in the payment amounts for Pickering and Darlington pursuant to Section 6(2)10 should take into account the amount of the Bruce costs required to be recovered under Section 6(2)9. The Board does not agree with CME's interpretation that Bruce nuclear liability costs are only recoverable to the extent that Bruce costs exceed Bruce revenues. As the Board understands CME's position, no costs related to the Bruce nuclear liabilities are recoverable by OPG whenever Bruce revenues exceed Bruce costs. In the Board's view, Section 6(2)10 does not in any way limit the Section 6(2)9 requirement that the Board ensure recovery of all costs incurred.

[78] OPG Reply Argument, page 112.

[79] Ibid.

[80] OPG Reply Argument, page 116.

The remaining issue is determining how the test period revenues and costs related to the Bruce stations should be measured. As noted earlier in this chapter of the decision, OPG has computed some test period revenues and costs for Bruce in accordance with GAAP but, in other cases, has used non-GAAP measures or included items that would not qualify as costs under GAAP.

In making its determination on how OPG's Bruce-related revenues and costs should be calculated for purposes of Sections 6(2)9 and 6(2)10 of the regulation, the Board first considered why the Province directed that any revenues or expenses related to Bruce should be included in the calculation of the payment amounts for Pickering and Darlington. In the Board's experience, it is unusual to decrease (or increase) rates for a regulated service by using the profits (or losses) of a separate, unregulated business that happens to be owned by the same entity.

OPG's involvement with the Bruce stations is quite different from its involvement with Pickering and Darlington. For example, the Board (and previously the Province) regulates the prices for energy production from the prescribed facilities. In contrast, the lease payments charged by OPG to Bruce Power (and the prices charged for engineering and other services) are the result of a commercial contract; they are not regulated by the Board or any other body. In addition, OPG operates the Pickering and Darlington plants and is responsible for offering the energy produced into the IESO electricity market. The Bruce plants are operated by Bruce Power, not OPG.

There was very little in the evidence in this hearing that explained why the regulation requires the Board to consider OPG's Bruce-related revenues and costs. The Bruce stations were not identified in the August 2004 draft regulation and consultation paper that was issued for public comment by the Ministry of Energy.[81] The first references to using Bruce revenues to reduce the payment amounts for the prescribed facilities appear to be in the December 2004 CIBC report. The executive summary of that report states:

> **OPG's Regulatory Construct**: We took as the starting point for OPG's regulatory construct the draft regulation and consultation paper for the initial rates for OPG's price regulated plants issued by the Ministry of Energy in August 2004. Following discussions with officials at the OFA and Energy, and based on its analysis, we provided several additional recommendations or variances from the draft consultation regulation and paper, as follows:

[81] The draft regulation and consultation paper are reproduced in Appendix J to the CIBC report.

- Use as an offset to OPG's regulated revenue requirement, OPG's revenues from the lease of its Bruce assets to Bruce Power, net of OPG's costs, which reduces the regulated rate.[82]

The CIBC report also notes that: "Whether these OPG assets are included or excluded under the regulation of OPG is a governmental policy issue rather than one that can be evaluated from regulatory precedents."[83]

Although not stated explicitly in any document issued by the Province to the Board's knowledge, it appears that the inclusion of the Bruce net revenues is essentially a mitigation measure. This view is supported by testimony of an OPG witness, who agreed that the inclusion of Bruce revenues and costs in the calculation of the payment amounts was intended to provide shelter against higher payments on the prescribed assets.[84]

In the Board's view, the fact that the net revenues related to OPG's unregulated Bruce lease are intended to mitigate the payment amounts for Pickering and Darlington does not lead to a conclusion that the Province must have intended that the Bruce revenues and costs be calculated as if OPG's investment in Bruce were subject to regulation.

Further, the Board finds that the Bruce net revenues, as a mitigation measure, do not form part of OPG's revenue requirement for the prescribed assets. Rather, the Board concludes that the regulation requires net revenues be used to reduce the payment amounts that would otherwise be set based on the revenue requirement for the prescribed assets. In the Board's view, "revenue requirement" is a concept that is applicable only to rate-regulated activities.

OPG advanced two arguments in support of its position that the rate base method should be used when calculating Bruce test period costs.

First, OPG has submitted that its use of the rate base method to calculate Bruce test period costs is consistent with the recommendations in the December 2004 CIBC report.

[82] CIBC report, page 2.

[83] CIBC World Markets report, page 20.

[84] Transcript, Volume 7, page 36.

It is true, as OPG notes, that page 20 of the CIBC report mentions “regulated rate base” when it refers to the Bruce stations. The Board is not convinced, however, that those words refer to OPG’s “rate base method” because the CIBC report uses different, and inconsistent, terminology when it discusses CIBC’s recommended treatment for the Bruce lease. For example, the CIBC report refers, in one place, to including “revenues from the lease of Bruce” in rate base, a concept that is difficult to understand because assets, not revenues, are included in rate base.[85] The Board also notes that other parts of the CIBC report that discuss the Bruce lease do not mention rate base at all but refer simply to using revenues from the Bruce lease as an offset to “OPG’s regulated revenue requirement”[86] or to including “lease cash flows from Bruce Power.”[87]

The CIBC report also states that rate base “reflects a company’s investment in assets related to its regulated business,”[88] which, in OPG’s case, does not include its investment in Bruce, an unregulated business.

In short, after reviewing the CIBC report to determine if it recommended the rate base method for calculating the Bruce test period costs, the Board is of the view that it did not.

OPG’s second argument was that when the Province set the initial payment amounts for the prescribed facilities, it deducted net revenues for the Bruce lease that had been calculated using the rate base method.

Aside from OPG’s claim, no evidence has been filed with this Board that sets out how the initial payments were calculated by the Province. The Board was unable to determine what was included in the rate base amount shown in the CIBC report; in any event, the initial payment amounts struck by the Province were different than the amounts set out in the CIBC report. The Board notes that a February 23, 2005 presentation on the payment amounts by Ministry of Energy officials indicated only that: “Earnings from the Bruce Nuclear Lease incorporated [sic] in the setting of the regulated

[85] CIBC Report, page 20.

[86] CIBC Report, pages 2, 27 and 34.

[87] CIBC Report, page 26.

[88] CIBC Report, page 10.

price of nuclear."[89] The term "earnings" does not suggest any particular basis of calculation.

The Board also notes that the "rate base" amount included in OPG's application is restricted to assets related to the prescribed facilities. No amounts related to the Bruce stations are included.

The Board concludes that the evidence is unclear as to whether the Province used the rate base method to calculate the net revenues for the Bruce lease when it set the initial payment amounts. Even if the rate base method were used to set the initial payments, however, the Board concludes it is not bound to continue that approach after April 1, 2008.

The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would not be a reasonable interpretation of Sections 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use. Had the Province intended the Board to determine revenues and costs related to Bruce in accordance with principles applicable to a regulated business, the regulation would have so stated.

OPG proposed to calculate Bruce lease revenue for the test period in accordance with a policy that would not be acceptable for an unregulated commercial entity. The company's rationale for following a cash basis of accounting for lease revenue, rather than a GAAP basis, is not clear to the Board.

OPG took the position that O. Reg. 53/05 requires the Board to accept OPG's cash basis accounting policy for Bruce lease revenue. Section 6(2)5 of the regulation requires the Board to accept certain amounts that are set out in OPG's 2007 audited financial statements, including "OPG's revenues earned with respect to any lease of the Bruce Nuclear Generating Stations." Section 6(2)6 stipulates that section 6(2)5 applies to "values relating to … the revenue requirement impact of accounting and tax policy decisions." OPG claimed that Section 6(2)6 obligates the Board to accept the

[89] Ministry of Energy, "Technical Briefing on OPG Pricing Announcement," February 23, 2005, page 8. [Exhibit J1.4]

accounting policy that was used by OPG to record lease revenue in 2007 when the Board determines OPG's Bruce lease revenue for the test period.

The Board does not accept that it is required to use the cash basis of accounting to calculate the test period revenues for the Bruce lease. In the Board's view, section 6(2)5 obligates the Board to accept the book values of assets and liabilities as at December 31, 2007 and requires the Board to accept the accounting policies that were used to compute those book values. Bruce lease revenue for the test period, an income statement amount for a period subsequent to 2007, is clearly not an asset or liability that is set out in OPG's 2007 financial statements. Those financial statements show lease revenue for 2007; the financial statements are not projections or forecasts of future revenues.

The Board will require that Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses. The Board's rationale is the same as its rationale for requiring that the cost of the Bruce nuclear liabilities be computed in accordance with GAAP – it is not reasonable to interpret the regulation to find that OPG can calculate revenues from an unregulated activity using an accounting policy that an unregulated company would not be permitted to use.

The Board directs OPG to revise its calculation of the net test period revenues related to Bruce as follows:

1. The rate base method should not be used to calculate OPG's costs in respect of Bruce. That means that "costs" should exclude the return on equity and deemed interest expense that flow from the rate base method.
2. OPG should base its calculation of costs on GAAP. The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs.
3. OPG should calculate lease revenue in accordance with GAAP.
4. OPG should include an income tax (PILS) provision, calculated in accordance with GAAP, in its computation of Bruce costs. OPG proposed to exclude income taxes on the basis that there are tax loss carry forwards available to the regulated businesses. As OPG's Bruce investment is not regulated by the Board,

the Board sees no basis for omitting a tax provision in the calculation of Bruce costs.

The net effect of these findings is that any profit (or loss) in respect of OPG's Bruce lease, calculated in accordance with GAAP, will increase (or decrease) the payment amounts for the prescribed assets. Under this approach, the payment amounts for the prescribed assets are likely to be lower in all cases than the payment amounts calculated under OPG's interpretation of O. Reg. 53/05. When OPG earns a profit (measured in accordance with GAAP) on its Bruce activities, the Board's approach calls for all of that profit to be used to reduce the payment amounts for Pickering and Darlington. OPG's approach would result in a smaller offset to the payment amounts because OPG would include a regulated return on its Bruce investment as a cost. If OPG were to incur a loss on its Bruce activities, which could happen if there are significant increases in the Bruce nuclear liabilities in the future, that loss would increase the payment amounts for the prescribed assets under the Board's approach. OPG's approach likely would result in a greater increase to the payment amounts, again because OPG would include a regulated return on its Bruce investment as a cost.

Under OPG's approach, as CCC and CME pointed out, electricity consumers would in effect be guaranteeing that OPG earns a return on its Bruce fixed assets. The Board has no evidence that supports such an approach, and believes the effect of such an approach on the nuclear payment amounts would not be reasonable. Under O. Reg. 53/05, electricity consumers, not OPG, are exposed to the risk that they will have to absorb, through higher payment amounts for the prescribed assets, any losses related to Bruce in the future. It is, therefore, appropriate that when OPG earns profits on its Bruce activities that consumers receive the full benefit of those profits, without deduction of a regulated return as proposed by OPG.

Calculating revenues and costs in accordance with GAAP will result in a higher excess of Bruce-related revenues over costs for the test period than the $134.4 million proposed by OPG. The Board estimates that the excess revenues under the GAAP approach are approximately $175 million (based on the GAAP pre-tax income amounts in Table 2, adjusted to reflect a 21-month test period, and tax rates of 31.5% in 2008 and 31.0% in 2009 as specified in OPG's application). The precise amounts will be determined by OPG and filed with the Board.

OPG did not apply for a variance account for test period revenues and costs in respect of the Bruce stations. Section 6(2)9 of the regulation requires the Board to ensure that OPG recovers all of its costs related to the Bruce stations. In the Board's view, this section obligates the Board to ensure OPG recovers its actual, not forecast, costs related to Bruce. Section 6(2)10 requires that the excess of revenues earned in respect of the Bruce stations over the costs incurred by OPG should reduce the payment amounts for the prescribed facilities. In the Board's view, this section obligates the Board to ensure that the actual, not forecast, excess of revenues over costs is used to offset the payment amounts for Pickering and Darlington. Accordingly, the Board directs OPG to establish a variance account to capture differences between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington, and (ii) OPG's actual revenues and costs in respect of Bruce. The cost impact of any changes in nuclear liabilities related to the Bruce stations should be recorded in this account, not the nuclear liabilities deferral account required by Section 5.2 of the regulation.

7 DEFERRAL AND VARIANCE ACCOUNTS

O. Reg. 53/05 authorized OPG to establish several deferral and variance accounts to record amounts for the period up to the effective date of the Board's first order under Section 78.1 of the *OEB Act*, which will be April 1, 2008. OPG has applied for clearance of deferral and variance accounts based on December 31, 2007 balances, which are set out in OPG's most recent audited financial statements. OPG indicated it will continue to record amounts in these accounts during the three-month period ending March 31, 2008 and will bring those balances forward for disposition in its next application.

Existing nuclear deferral and variance accounts are addressed in section 7.1. Existing hydroelectric accounts are covered in section 7.2.

OPG also applied for several new deferral and variance accounts and intervenors also recommended some new accounts. Proposed new accounts are addressed in section 7.3. The rate to be used to accrue interest on the account balances is covered in section 7.4.

7.1 Existing Nuclear Accounts

Table 7-1 sets out the nuclear deferral account balances at December 31, 2007. OPG proposed to recover $128.1 million of the balance during the 21-month test period via a nuclear rate rider of $1.45 per MWh.

Table 7-1: Nuclear Deferral and Variance Accounts, December 31, 2007

Account	Amount *$ millions*	Reg. 53/05 Section	Recovery Period	
			OPG Proposal	Maximum per Reg. 53/05
Pickering A return to service	**$ 183.8**	5 (4)	11.75 years	15 years
Nuclear liability	**130.5**	5.1	2.75 years	3 years
Nuclear development - New facilities	**11.7**	5.3	2.75 years	3 years
Nuclear development - Capacity refurbishments	**16.2**	6 (2) 4	2.75 years	n/a
Ancillary services	**(1.7)**	5 (1) (c)	2.75 years	3 years
Transmission outages and restrictions	**1.6**	5 (1) (e)	2.75 years	3 years
Total	**$ 342.1**			

Sources: Ex. J1-2-1, Table 4; O. Reg. 53/05.

7.1.1 Pickering A return to service (PARTS)

This deferral account records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station. Section 5(4) of O. Reg. 53/05, as amended in 2007, authorized OPG to include costs related to the Pickering units that OPG determined will not return to service, being Units 2 and 3. The regulation also permits OPG to include interest on the balance at an annual rate of 6%.

Section 6(2)3 of the regulation requires the Board to ensure OPG recovers the balance in this account on a straight-line basis over a period not to exceed 15 years.

OPG recorded non-capital costs in this account totalling $271 million (mostly related to Pickering A Unit 1). The company commenced amortization of the costs in 2005. The December 31, 2007 balance of $183.8 million is net of the accumulated amortization and includes interest.

Section 6(2)(5) of O. Reg. 53/05 requires that, in making its first order under section 78.1 of the *OEB Act*, the Board shall accept amounts as set out in OPG's most recently audited financial statements, which are as at and for the year ended December 31, 2007. The PARTS deferral account balance is included in those financial statements.

OPG concluded that the long recovery period of 11 years and nine months is appropriate because the costs were incurred to extend the service life of Pickering A. Most of the costs related to extending the service life of Unit 1, which OPG estimates has an “end of life” date of 2021. The proposed recovery during the test period is $27.4 million.

Intervenors and Board staff did not contest the balance in the PARTS account or the proposed recovery period.

Board Findings

OPG’s evidence was that the balance in the PARTS account has been recorded accurately. None of the parties in this proceeding objected. The account balance is set out in OPG’s audited 2007 financial statements and O. Reg. 53/05 requires the Board to accept that amount.

OPG has proposed a lengthy recovery period on the basis that the account is associated with a long-term asset, Pickering A, that is expected to generate electricity over the period to 2021.

The Board does not find this rationale convincing. Although the costs may be “associated” with the Pickering A return to service project, the fact remains that they are non-capital costs that, absent the regulation, would not have been capitalized and amortized under generally accepted accounting principles. In the Board’s view, there is no compelling rationale for linking recovery of the costs to the service life of Pickering A.

Under OPG’s proposal, the recovery of the balance in the PARTS account during the test period would be $27 million. This is substantially lower than the test-period recovery of the nuclear liability deferral account of $83 million, which is being recovered over a three-year period and is addressed later in this chapter. The Board concludes that it is appropriate to recover the PARTS account balance over a shorter period than that proposed by OPG. The Board approves recovery over the period April 1, 2008 to December 31, 2011.

7.1.2 Nuclear liability deferral account

O. Reg. 53/05 was amended in 2007 to require OPG to establish a deferral account to capture certain amounts related to changes in nuclear liabilities that occurred after April 1, 2005 and before the effective date of the Board's first order. The regulation requires the Board to ensure that the balance in this account is recovered on a straight-line basis over a period not to exceed three years. The regulation also requires OPG to accrue interest on the account balance at an annual rate of 6 per cent.

On December 31, 2006, OPG recorded an increase of $1,386 million in its nuclear decommissioning and nuclear waste management liabilities. In accordance with Canadian generally accepted accounting principles, OPG also increased the net book values of the relevant nuclear stations by an equal amount. The increases in the net book values at the end of 2006 for these asset retirement costs, or ARC, were $878 million for the Bruce stations and $508 million for the Pickering and Darlington stations.

The balance in the nuclear liability deferral account as at December 31, 2007 was $130.5 million. The components of the balance are shown in Table 5-6 in Chapter 5.

Chapter 5 of this decision (section 5.3.3) sets out the submissions by OPG and intervenors, and Board findings, on the two significant issues related to this account balance: OPG's use of the rate base method to calculate the account balance, and the inclusion of costs related to the increase in the Bruce nuclear liabilities. Except for those two issues, intervenors did not comment on OPG's calculation of the other components of the account balance.

Board Findings

In section 5.3.3 of this decision, the Board found that it would accept including in the deferral account a return of 5.55% on the average unamortized ARC related to the increase in nuclear liabilities. The Board also found that it would accept the inclusion of costs related to the increase in the Bruce nuclear liabilities in this account. There were no questions raised by any party with respect to the entries in the account for depreciation and the other expenses.

The Board accepts disposition of the balance in this account over the period proposed by OPG.

7.1.3 Nuclear development – New facilities

On June 16, 2006, the Minister of Energy directed OPG to begin a federal approvals process, including an environmental assessment, for new nuclear units at an existing site. Section 5.3 of O. Reg. 53/05 authorizes a deferral account to record costs incurred and firm financial commitments made on or after June 13, 2006 in the course of carrying out these activities, for the period up to the effective date of the Board ‘s first order. The regulation permits OPG to include interest on the balance at an annual rate of 6%.

The new nuclear facilities deferral account balance is included in OPG’s audited 2007 financial statements. The balance at December 31, 2007 is made up of costs to explore development of new capacity at the Darlington site plus interest.

Section 6(2)7.1 of the regulation requires the Board to ensure OPG recovers the balance in this account on a straight-line basis over a period not to exceed three years. OPG has proposed that recovery take place over two years and nine months, being the 21-month test period plus one additional year.

Intervenors and Board staff did not contest the balance in this account or the proposed recovery period.

Board Findings

OPG’s evidence was that the balance in this account has been recorded accurately and no party disputed that. The balance is set out in OPG’s audited 2007 financial statements. The Board approves recovery of the balance as proposed by OPG.

7.1.4 Nuclear development – Capacity refurbishments

The June 16, 2006 directive from the Minister of Energy on new nuclear facilities also required OPG to begin feasibility studies on refurbishing its existing nuclear units. The Minister directed OPG to begin an environmental assessment on the refurbishment of the four units at Pickering B.

OPG has deferred $16.2 million at December 31, 2007, being non-capital costs related to exploring refurbishment of Pickering and Darlington. OPG stated that these

expenditures were not included in forecast information provided to the Province when the existing payment amounts were set in 2005.
O. Reg. 53/05 does not establish deferral or variance accounts for pre-April 1, 2008 spending on assessing the feasibility of refurbishing Pickering or Darlington. OPG supported the deferral and recovery of these expenditures by reference to Section 6(2)4 of O. Reg. 53/05, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2 [the prescribed generation facilities], including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

OPG also submitted that the Board is obligated to approve recovery of the account because the balance is set out in OPG's 2007 audited financial statements, and because the costs incurred were within approved project budgets.

None of the intervenors objected to OPG's recovery of this balance.

Board Findings

This is the only nuclear deferral or variance account established by OPG that is not expressly authorized by O. Reg. 53/05.

The Board does not dispute that OPG incurred the costs in response to a directive from the Minister of Energy or that OPG recorded the costs accurately. The issue is whether the Board has any authority to approve recovery of out-of-period OM&A expenses booked in a deferral account that is not expressly authorized by O. Reg. 53/05.

OPG argues that Section 6(2)4 implicitly authorizes a deferral account because that section requires the Board to ensure OPG recovers costs related to refurbishing nuclear facilities, including assessment costs and pre-engineering costs and commitments.

The Board did not set payment amounts for the period April 1, 2005 to March 31, 2008. Its jurisdiction to set payment amounts, found in section 78.1 and O. Reg. 53/05, commences with the effective date of the Board's first order, which is April 1, 2008.

The Board has concluded that Section 6(2)4 can only reasonably be interpreted as being applicable to refurbishment-related OM&A expenses incurred on or after April 1, 2008. In the Board's view, had the government intended the Board ensure OPG recovers pre-April 2008 OM&A expenses for refurbishment activities, O. Reg. 53/05 would have explicitly directed such recovery, as they did with certain pre-April 2008 nuclear activities.

O. Reg. 53/05 requires the Board to ensure OPG recovers three specific pre-April 2008 non-capital costs related to nuclear activities: (i) Section 5(4) established a deferral account for non-capital costs related to the Pickering A return to service project; (ii) Section 5.1 authorized a deferral account for costs related to pre-April 2008 changes in nuclear liabilities; and (iii) Section 5.3 authorized a deferral account for pre-April 1, 2008 costs associated with planning new nuclear generation. In the Board's view, the fact that the government chose to direct the Board to ensure recovery of these specific pre-April 2008 non-capital costs supports the reasonableness of its interpretation of Section 6(2)4. In each instance, the government chose clear and explicit language when it intended the Board to ensure recovery of out-of-period non-capital costs. Absent such clear and explicit direction, the Board finds no basis on which to grant OPG recovery of non-capital costs incurred before April 1, 2008.

Additional support for the Board's interpretation of Section 6(2)4 is found in the most recent amendment to O. Reg. 53/05. Section 6(2)4.1 was added to the regulation in February 2008. It requires the Board to ensure that OPG recovers the costs incurred in the course of planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 53/05 uses the same language to direct recovery under section 6(2)4.1 as it did to direct recovery of refurbishment costs under Section 6(2)4 ("The Board shall ensure Ontario Power Generation Inc. recovers …").

Logically, OPG's interpretation of implicit authorization should be equally applicable to Section 6(2)4.1, that is, the creation of a deferral account to capture the costs directed to be recovered should be implicitly authorized by Section 6(2)4.1.

It is notable that when the government added section 6(2)4.1 to O. Reg. 53/05, it also added Section 5.3, a deferral account to capture the pre-April 2008 costs related to new nuclear activity. If OPG's interpretation was correct, the government would not have needed to do so as the authorization for the Section 5.3 deferral account would have been implicitly authorized by Section 6(2)4.1. That the government found it necessary to add Section 5.3 supports the Board's finding that absent clear and express direction to the contrary, the Board does not have the jurisdiction to review or order recovery of pre-April 2008 costs.

For the reasons above, the Board does not approve recovery of the $16.2 million recorded in this account.

7.1.5 Ancillary services/transmission outages and restrictions

The balances in these two accounts are relatively small and OPG's evidence is that the amounts are accurately recorded in accordance with O. Reg. 53/05. None of the intervenors objected to OPG's recovery of these balances.

Board Findings
The Board approves recovery of the balances as proposed by OPG.

7.2 Existing Hydroelectric Accounts

The December 31, 2007 hydroelectric deferral and variance account balances are much smaller than the nuclear balances and are presented in Table 7-2.

Because the net balance is relatively small, OPG did not propose a separate rate rider for recovery of the hydroelectric accounts. Instead, it proposed to deduct the net credit balance of $2.8 million from the test period hydroelectric revenue requirement.

Table 7-2: Hydroelectric Deferral and Variance Accounts, December 31, 2007

Account	Amount ($ millions)	Reg. 53/05 Section	Recovery Period	
			OPG Proposal	Maximum per Reg. 53/05
Water conditions	**$ 6.7**	5 (1) (a)	1.75 years	3 years
Ancillary services	**6.7**	5 (1) (c)	1.75 years	3 years
Segregated mode of operations	**(11.5)**	n/a	1.75 years	n/a
Water transactions	**(3.0)**	n/a	1.75 years	n/a
Interest (6%)	**(1.7)**	5 (3)	1.75 years	3 years
Total	**$ (2.8)**			

Sources : Ex. J1-1-1, Table 2; O. Reg. 53/05.

The accounts for segregated mode of operations (SMO) and water transactions are not required by O. Reg. 53/05. OPG earns revenue from segregating some of the units at the Saunders plant from the Ontario transmission system and reconnecting them directly to the Quebec grid. OPG also earns revenue when a portion of its Niagara water entitlement is used at the New York Power Authority's generating facilities. The balances in these deferral accounts are portions of OPG's net profits from these activities from April 1, 2005 to December 31, 2007. OPG has voluntarily proposed to share the profits because the SMO and water transactions were earned through the use of prescribed generation facilities.

No intervenors took issue with either the balances in the hydroelectric deferral and variance accounts or OPG's proposed method of recovery.

Board Findings

The Board accepts the balances in the hydroelectric deferral and variance accounts required by O. Reg. 53/05 and recovery of those balances over the test period.

As for the SMO and water transaction accounts, the Board concludes there is no basis for permitting clearance of this account. OPG is proposing to voluntarily share profits from SMO and water transactions that are not caught by O. Reg. 53/05 and that occurred before the Board took over regulating OPG's payment amounts. As noted earlier in this chapter in section 7.1.4 under "Nuclear development – Capacity refurbishments," the Board has concluded that it has no authority under O. Reg. 53/05 to make determinations on costs incurred or revenues earned by OPG before the effective date of the Board's first order unless there is express provision to that effect in the regulation.

The Board will not take these historical revenues into account when setting the OPG payment amounts.

7.3 Test Period Deferral and Variance Accounts

7.3.1 Continuation of existing accounts

O. Reg. 53/05 requires OPG to utilize three deferral or variance accounts for periods after the date of the Board's first order. Those accounts are:

- Pickering A Return to Service deferral account, per O. Reg. 53/05, Section 5(4),
- Nuclear liability deferral account, per Section 5.2, and
- Nuclear development variance account, per Section 5.4.

In addition, OPG proposed to continue these variance accounts:

- **Hydroelectric water conditions variance account**
  This account is to capture the revenue impacts of differences in hydroelectric electricity production due to differences between forecast and actual water conditions for the prescribed facilities. OPG indicated this is a continuation of the account authorized by Section 5(1)(a) of O. Reg. 53/05 for the period up to the date of the Board's first order.
- **Ancillary services variance account**
  OPG also proposed to continue the ancillary services variance account authorized by Section 5(1)(c) of O. Reg. 53/05. The account is intended to record variances between ancillary services revenues from the IESO included in the test period revenue requirement and the revenues actually realized.
- **Capacity refurbishment variance account**
  Section 6(2)4 of O. Reg. 53/05 requires the Board to ensure that OPG recovers capital and non-capital costs, and firm financial commitments, incurred to

increase the output of, refurbish or add operating capacity to a prescribed generation facility. This variance account is intended to capture differences between forecast amounts of such costs included in the test period revenue requirement and actual costs incurred.

Intervenors either supported OPG's request for these accounts or were silent in their submissions.

Board Findings

The Board authorizes OPG to establish the hydroelectric water conditions and ancillary services for the test period. As discussed earlier in this chapter, the Board disallowed the balance in the capacity refurbishment variance account proposed by OPG for the period before April 1, 2008. In light of the obligation imposed on the Board by Section 6(2)4, the Board accepts that a variance account is required for the period beginning April 1, 2008 and authorizes OPG to establish the capacity refurbishment variance account.

O. Reg. 53/05 requires OPG to maintain the PARTS, nuclear liability, and nuclear development accounts. As discussed in Chapter 5 on nuclear liabilities, the Board finds that the nuclear liability deferral account required by O. Reg. Section 5.2 should be restricted to the revenue requirement impact of changes in nuclear liabilities related to the prescribed nuclear facilities at Pickering and Darlington.

7.3.2 New Accounts Proposed by OPG

OPG requested approval to establish four new variance accounts:

- **Nuclear fuel expense**
  This account would capture the difference between the forecast and actual nuclear fuel expense during the test period. OPG proposed to determine a per MWh fuel expense based on the forecast fuel expense and production levels in its application. Entries to the account would be made when OPG's actual fuel expense per MWh differs from the forecast.

- **SMO, water transactions**
  This account would hold electricity consumers' shares of OPG's revenues from energy sales when the R.H. Saunders plant is segregated from the Ontario system, and consumers' share of revenues from water transactions with the New York Power Authority.

- **Pension/OPEB interest**
  OPG proposed this account to capture the impact of changes in the discount rate used to determine pension and other post-employment benefit (OPEB) costs. OPG is required by GAAP to reset the discount rate annually based on the state of the bond markets. The proposed account would only be cleared when the accumulated variance in pension and OPEB costs caused by a change in the discount rate, plus the forecast variance to the end of the bridge year, exceeds $75 million.

  The forecast pension costs for the test period have been calculated using a discount rate of 5.60%,[90] being the rate used by OPG to calculate the present value of its pension obligation at the end of 2007. OPG submitted that a change in discount rate, which is outside OPG's control, could have a material effect on pension and OPEB costs. It estimated that a 25 or 50 basis point change in the discount rate would result in a $50 million or $110 million change in pension and OPEB costs per year, assuming all other factors affecting the costs remain unchanged.

- **Changes in tax rates, rules and assessments**
  OPG proposed that differences between actual and forecast taxes, due to the following factors, be recorded in this account: (i) changes to tax laws that govern the determination of payments in lieu of income taxes, capital taxes, and property taxes; (ii) legislative or regulatory changes to municipal property tax rates; (iii) changes in, or disclosure of, new assessing or administrative policies of federal or provincial tax authorities, or court decisions for other taxpayers that will affect OPG; and (iv) tax assessments or re-assessments.

OPG also included in its application six potential future accounts that it wanted to "bring to the Board's attention the possibility that OPG may apply for a variance account via an

[90] Exhibit F3-4-1, page 24.

accounting order application in the event unforeseen material events/activities occur." The Board did not consider the potential accounts as OPG did not apply for the accounts.

There were no objections by any party to OPG establishing the nuclear fuel expense and SMO/water transactions variance accounts. Several intervenors did take exception to OPG's proposals for the pension/OPEB cost and tax variance accounts.

AMPCO, CCC, CME, SEC and VECC opposed the proposed pension and OPEB interest variance account. They argued that the Board should take the same approach for variances in OPG's pension and OPEB costs as it does for other entities regulated by the Board. CCC submitted that forecast risk and interest rate risk are fundamental business risks for a regulated entity, and that shareholders are compensated for such risks through the deemed capital structure and return on equity.

SEC noted, and OPG agreed, that the discount rate is only one factor that determines the amount of OPG's pension and OPEB costs in any year. SEC submitted that changes in other factors that affect OPG's pension and OPEB costs could lead to decreased costs. Allowing the proposed variance account, in SEC's view, would amount to single issue ratemaking.

OPG cited four Board decisions on rates for electric utilities in which the Board approved deferral or variance accounts for pension costs. OPG argued that the variance accounts for pension costs of Hydro One's distribution and transmission businesses provide a greater level of protection than the account sought by OPG.

In response to SEC's comment that the proposed account would capture the effects of only one cause of variation in pension and OPEB costs, OPG said it would not oppose increasing the scope of the account to capture the impact of changes in all factors.

Intervenors generally supported, or were silent on, the need to establish a variance account for taxes but several parties expressed concerns about OPG's specific proposal.

CCC supported the use of the account only for the effect of tax assessments and re-assessments related to the period after April 1, 2008, the effective date of the Board's first order. CME and SEC submitted that the parameters of the account should be compatible with those for the tax deferral account approved for use by electricity distributors. CME also submitted that the cost consequences of tax re-assessments for periods before April 1, 2008 should not automatically be recoverable in rates; for such re-assessments, CME suggests the Board should deal with requests for relief on a case-by-case basis. VECC also requested that before OPG clears any balances in the account in respect of re-assessments for past periods, customers should have an opportunity to explore the circumstances leading to the re-assessment.

OPG objected to CCC's proposal that the tax variance account be used solely for the impacts of tax assessments and reassessments for the period after April 1, 2008. OPG has resolved all issues related to the audit of its 1999 tax return,[91] and indicated it has incorporated the results of that audit in its estimate of tax losses for the 2005 to 2007 period. Based on the amount of those losses, OPG did not include any tax provision in test period costs. OPG submitted, however, that the results of audits of 2000 and later tax years could materially affect the amount of estimated tax losses for 2005 to 2007. OPG explained its rationale for requesting that the impact of all reassessments be recorded in the variance account as follows:

> OPG is seeking the inclusion of impacts of reassessments for the years prior to regulation by the OEB because it is voluntarily providing the benefits of the calculated tax losses from the 2005 to 2007 period. If there is a reassessment that reduces the actual losses for 2005 to 2007, then OPG would have given ratepayers a benefit that turns out not to have existed. In this circumstance, OPG believes it is entirely appropriate to include reassessments in the tax variance account.[92]

Board Findings

Nuclear fuel expense

The Board approves the nuclear fuel expense variance account as proposed by OPG.

[91] OPG's 2008 Second Quarter Report, at pages 24 and 25, stated:

> In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit were unique to OPG and related either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998*. In the first quarter of 2008, a number of outstanding tax matters related to the 1999 tax audit were substantially resolved and as a result, OPG reduced its income tax liability by $85 million. During the second quarter of 2008, all remaining issues relating to the 1999 tax audit were resolved resulting in a further reduction of OPG's income tax liability of $21 million.

[92] OPG Reply Argument, page 147.

SMO and water transactions

In Chapter 3, the Board determined that revenues from SMO and water transactions would not be subject to variance account treatment, so there is no need for the Board to approve the proposed variance account.

Pension interest rate

The Board does not approve the proposed variance account related to changes in the discount rate used for pensions and OPEBs. The Board acknowledges that changes in the discount rate are outside OPG's control but that is true of many elements of OPG's proposed revenue requirement.

It has not been the Board's practice to allow regulated entities to establish variance accounts for changes in the costs of pensions and other benefits although there have been a few exceptions, as noted by OPG. The Board does not consider the two Board decisions on Hydro One's pension deferral accounts, which were cited by OPG, to be analogous to OPG's proposal. Unlike the account OPG has requested, the deferral account that Hydro One Distribution sought, and was granted, in 2004 was not intended to capture changes in pension costs that had not occurred but that might arise due to future changes in economic factors. Rather, the Hydro One Distribution account was established for known and material increases in pension costs above the amount included in rates.[93] The other Hydro One pension deferral account referenced by OPG (an account established in 2007 for Hydro One Transmission) was part of a settlement agreement accepted by the Board. As the Board has noted on other occasions, specific elements of settlement agreements have limited precedential value.

In the event that OPG's actual pension and OPEB costs during the test period are materially in excess of the amounts included in the revenue requirement, OPG would have the ability to apply to the Board.

Income and other taxes

The Board approves the variance account to track variations in municipal property taxes, and variations in payments in lieu of capital taxes, property taxes, and income taxes. The Board has authorized a tax variance account for electricity distributors (Account 1592, which deals with tax variances after April 2006[94]) that is used to record

[93] RP-2004-0180/EB-2004-0270, Decision and Order, July 14, 2004.

[94] Account 1592 is described in the Board's Accounting Procedures Handbook for Electric Distribution Utilities.

variations due to changes in tax rates or rules, new assessing or administrative practices of tax authorities, and tax re-assessments for past periods. The events and circumstances that give rise to entries into Account 1592 are essentially the same as those proposed by OPG, except that OPG includes court decisions for other taxpayers that will affect OPG's tax position. The Board finds that OPG's inclusion of variations due to court decisions for other taxpayers is appropriate.

The Board does not accept CCC's argument that only variances due to tax re-assessments for periods after April 1, 2008 should be permitted. The Board does not consider it appropriate to make use of the account more restrictive than Account 1592 is for electricity distributors.

With respect to income taxes, it is necessary to determine what the benchmark should be for measuring variations due to changes in tax laws and other factors. OPG did not address this issue in its evidence or argument. This is complicated by the fact that OPG did not include any provision for income taxes in its proposed revenue requirement on the basis that there are tax loss carry forwards for regulatory purposes. As set out in Chapter 9, the Board is uncertain about whether such regulatory tax loss carry forwards exist and, if they do, whether OPG was required to adopt the approach it took in its application.

To establish a benchmark to measure variations in taxes during test period, the Board directs OPG to calculate the income tax provision, before consideration of any tax loss carry forwards, which would result from the revenue requirement determined in accordance with this decision. That tax provision will not form part of the test period revenue requirement but should be used by OPG to calculate any variations in taxes that it records in the variance account.

The appropriateness and recovery period of any balance in the tax variance account will be reviewed by the Board when it considers OPG's next application. The Board notes that it has commenced a proceeding to deal with the disposition of Account 1562 (the tax variance account for electricity distributors for periods before May 2006) and that proceeding is expected to deal with variations in taxes due to tax audits and reassessments for past periods.[95] In a future hearing when the Board reviews any

[95] The Account 1562 proceeding (EB-2007-0820) was announced in March 2008. A staff discussion paper on the issues was released on August 20, 2008.

balance in OPG's tax variance account related to re-assessments, it will take note of any relevant decisions made by the Board in the Account 1562 proceeding.

7.3.3 New accounts proposed by intervenors

Two intervenors suggested that OPG be required to establish additional variance and deferral accounts.

In connection with its submission that the Board should cut OPG's proposed regulatory costs by 50%, CCC stated that OPG could establish a regulatory cost variance account to capture deviations from budget as OPG gains more experience with regulatory forecasting.

AMPCO recommended a variance account be approved in connection with its proposal that OPG be required to share 50% of any Congestion Management Settlement Credits received by OPG from the IESO, net of incremental costs.

AMPCO also proposed a variance account to capture variances between actual and forecast non-energy charges from the IESO (which OPG pays when the prescribed facilities consume power). AMPCO said these charges are difficult to forecast and submitted that OPG's forecasting methodology is questionable.

OPG did not agree that these accounts are required. It said its test period budget for regulatory costs is appropriate because it plans to file another cost of service application with the Board in 2009. It disagreed with AMPCO's submission that there is any net revenue from CMSC payments. And it disputed AMPCO's claim that OPG's forecasting methodology is suspect.

Board Findings
The Board agrees with OPG comments on the proposed accounts. It will not require OPG to establish the accounts. As noted in Chapter 4, the Board accepts OPG's forecast of regulatory costs and found a variance account is not required.

7.4 Interest Rates

OPG proposed that, for all deferral and variance accounts except PARTS, interest after March 31, 2008 should be accrued on the account balances at OPG's forecast rate for other long-term debt of 5.65% for 2008 and 6.47% for 2009.[96] For the PARTS account, OPG proposed to accrue interest using the weighted average cost of capital (WACC), which OPG proposed to be 8.48% for 2008 and 8.56% for 2009.

AMPCO, CCC, CME, VECC, and Board staff objected to OPG's proposed interest rates. They submitted that the rates should be set in accordance with the Board's interest rate methodology for regulatory accounts.[97] The arguments in favour of that approach were essentially that an unfortunate regulatory precedent would be set if the Board allowed OPG to depart from the Board's policy and that OPG has not established that its circumstances are sufficiently different from those of other regulated entities to justify special treatment.

Under the Board's policy, the interest rate for deferral and variance accounts is set each quarter at the prevailing three-month Bankers' Acceptance rate plus 25 basis points. The interest rate for the three months beginning April 1, 2008 was 4.08%. The rate was reset effective July 1, 2008 to 3.35%, and was kept at that level effective October 1, 2008.

OPG argued that its circumstances are substantially different from those of distribution utilities in terms of the size of the account balances and the length of time until full recovery. OPG noted the interest rates allowed by the Board in 2004 (before the Board's policy was issued) on the substantial deferral account balances for market ready and other transitional costs of electricity distributors were based, at least for some distributors, on long-term debt rates. OPG also submitted that it would be carrying deferral and variance account balances for longer periods than the distributors.

OPG characterized its request to use WACC to accrue interest on the PARTS account as an "exceptional situation" given OPG's proposed recovery period of almost 12 years.

Board Findings

The Board is not persuaded that OPG's circumstances are sufficiently different from those of other regulated entities to justify interest rates that are higher than those permitted by the Board's policy.

[96] The proposed rates are set out in the pre-filed evidence at Exhibit C1-2-1, Tables 2 and 3.

[97] The policy is set out in a November 28, 2006 letter to Natural Gas Utilities and Electricity Local Distribution Companies, and is on the Board's website at http://www.oeb.gov.on.ca/documents/cases/EB-2006-0117/letter_accountinginterest_281106.pdf.

With the exception of the PARTS account, the Board has approved recovery of the balances in the existing deferral and variance accounts over periods not exceeding two years and nine months. With respect to PARTS, the Board determined that OPG should recover that balance over three years and nine months. These recovery periods are not substantially longer than the recovery periods for many deferral accounts of other regulated entities. And, in some cases, electricity distributors have been carrying deferral and variance accounts for longer periods.

With the Board's decision to shorten the recovery period for the PARTS account, the Board does not agree that the PARTS account represents an exceptional situation. The Board notes that, even if it agreed that an exception to its policy were warranted, it would not have granted OPG's request to accrue interest using OPG's WACC. Deferral and variance accounts are not rate base items and should not attract a rate base type of return.

The Board directs OPG to accrue interest on deferral and variance account balances after March 2008 using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy.

8 RATE BASE AND COST OF CAPITAL

8.1 Rate Base

OPG submitted that O. Reg. 53/05 requires the Board to accept the assets and liabilities as established by OPG's audited 2007 financial statements. The proposed regulated hydroelectric rate base is $3,885.5 million in 2008 and $3,869.9 million in 2009 and the proposed regulated nuclear rate base is $3,515.4 million in 2008 and $3,453.8 million in 2009. OPG has used the 2007 financial statements as the starting point and used the mid-year average methodology for in-service additions within the period. OPG maintained that capital costs for in-service additions included construction work in progress in 2007 financial statements and must be accepted for inclusion in rate base.

Table 8-1: Proposed Rate Base

	Hydroelectric		Nuclear	
$ millions	**2008**	**2009**	**2008**	**2009**
Gross plant at cost	4,433.2	4,480.6	4,531.7	4,733.2
Accumulated depreciation	570.2	633.1	1,737.8	2,037.1
Net Plant	3,863.1	3,847.5	2,794.0	2,696.0
Cash working capital	21.8	21.8	16.0	16.0
Fuel inventory	0.0	0.0	281.1	330.1
Materials and supplies	0.6	0.6	424.4	441.7
Total	**3,885.5**	**3,869.9**	**3,515.4**	**3,483.8**

Source: Ex B1-1-1, Tables 1 and 2.

Board Findings

The treatment of liabilities associated with nuclear waste management and decommissioning was the only significant aspect of rate base which was disputed in the proceeding. The Board's findings on that issue are set out in Chapter 5, namely that the return awarded on the rate base associated with the unamortized ARC and unfunded liabilities for Pickering and Darlington will be 5.6%. The balance of the rate base will be used for purposes of determining the amounts to be included in the revenue requirement for cost of capital related to the deemed capital structure and the return on equity. The Board accepts the remainder of the proposed rate base. If adjustments are needed as a consequence of any other findings in this decision, OPG should detail those adjustments in its draft order.

8.2 Capital Structure and Cost of Capital – Introduction

OPG's interim rates are based on a debt/equity ratio of 55/45 and a return on equity (ROE) of 5%. The following table sets out OPG's proposed capital structure and cost of capital for 2008 and 2009.

Table 8-2: Proposed Capital Structure and Cost of Capital

	2008		2009	
	% of Capital Structure	Rate	% of Capital Structure	Rate
Short-Term Debt	2.6%	5.83%	2.6%	5.98%
Existing/Planned Long-Term Debt	29.7%	5.79%	32.1%	5.79%
Other Long-Term Debt Provision	10.3%	5.65%	7.8%	6.47%
Total Debt	**42.5%**	**5.76%**	**42.5%**	**5.92%**
Common Equity	**57.5%**	**10.50%**	**57.5%**	**10.50%**
Total Rate Base	**100%**	**8.48%**	**100%**	**8.56%**

Source: Ex. C1-2-1, Tables 2 and 3.

OPG also proposed that the Board adopt a formula to be used for future adjustments to the ROE.

Ms. McShane provided evidence for OPG. Intervenors also presented expert evidence as follows:

- Board staff sponsored evidence by Mr. Goulding.
- The Pollution Probe Foundation (Pollution Probe) sponsored evidence by Drs. Kryzanowski and Roberts.
- VECC and CCC sponsored evidence by Dr. Booth.
- Energy Probe sponsored evidence by Dr. Schwartz.
- Green Energy Coalition (GEC) sponsored evidence by Mr. Chernick.
- AMPCO sponsored evidence by Dr. Murphy and Mr. Adams.

The following table summarizes the quantitative evidence of the witnesses.

Table 8-3: Summary of Expert Recommendations

Expert	Return on Equity	Capital Structure	
		Debt	Equity
Ms. McShane		42.5%	57.5%
Equity Risk Premium test	9.5-10.25%		
Discounted Cash Flow test	9.5-10.0%		
Comparable Earnings test	12.5%		
Recommendation	10.50%		
Dr. Kryzanowski / Dr. Roberts	7.35% (2008) 7.40% (2009)	53%	47%
Dr. Booth	7.75%	60%	40%
Dr. Schwartz	7.64%	55%	45%

This chapter will address the following issues:

- Capital structure
- Return on equity
- Cost of debt

8.3 Capital Structure

8.3.1 Approach to setting capital structure

CME submitted that the Board should begin with the premise that the debt/equity structure determined by the Province for purposes of setting the payments in the interim period was appropriate and that the structure should only change if there has been a material change in OPG's risks. CME pointed to OPG's testimony that its risks had not changed.

OPG responded that this position would have some merit if the prior capital structure had been set by the Board. OPG submitted that the Province adopted the interim equity ratio "as a transition to full cost of service rates established after an independent review by the OEB."[98] OPG pointed out that the level was set without a thorough cost of capital study and O. Reg. 53/05 clearly makes the Board the authority to set the payments. OPG also argued that if the Province thought the capital structure was appropriate, it could have indicated as such in O. Reg. 53/05. In OPG's view, the fact that the O. Reg. 53/05 does not stipulate the equity ratio supports the conclusion that the Province expected the Board to make its determination of the cost of capital on a commercial basis.

Board Findings

The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities.

The equity ratio underlying the interim rates is informative, but not determinative for purposes of the Board's decision; rather it is an expression of the Province's expectations at that time and its assessment of what would be reasonable in the circumstances. The Board agrees that an important distinction is that the equity ratio was not set under the auspices of a Board proceeding with evidence, testimony and argument.

The following factors were raised in the context of the risk assessment, each of which will be addressed in turn:

- The stand-alone principle
- Regulatory risk
- Operating risk

8.3.2 The stand-alone principle

Many regulated utilities are part of a broader entity that includes affiliates or non-regulated operations. Under the stand-alone principle, the regulated operations of the utility are treated for regulatory purposes as if they were operating separately from the other activities of the entity. The intent is that the cost of capital borne by customers, in respect of the regulated operations, should not reflect subsidies to or from other activities of the firm and should only reflect the business risks associated with the regulated operations.

[98] OPG Reply Argument, p. 9.

OPG has several characteristics which differentiate it from other utilities regulated by the Board. Both the regulated and unregulated operations are in the business of generating power for sale into the Ontario market; both the regulated and unregulated operations are owned by the Province. It is also the Province that has determined, in certain respects, the Board's current and future approach to setting payment amounts. That is the context in which the Board considers the application of the stand-alone principle to the regulated operations of OPG.

At issue in the hearing was whether in the course of setting an appropriate capital structure, the application of the stand-alone principle excluded a consideration of the significance of the Province's ownership of OPG as part of the assessment of business risks associated with the regulated operations.

OPG's position is that the matter of ownership should not be taken into account, and the cost of capital for the regulated operations should reflect what the cost would be if OPG were raising capital in the public markets on the strength of their own business and financial parameters. OPG noted that Mr. Goulding and Drs. Kryzanowski and Roberts agree that the stand-alone principle is a fundamental principle in determining the cost of capital.

OPG also noted that Mr. Goulding recognized the political risk which OPG faces due to changing power sector policies and that the bond rating agencies have highlighted political risk. Mr. Goulding's evidence was that the prescribed assets face greater political risk than transmission, distribution or merchant generators because these other entities are less likely to be used directly by government for policy purposes. Ms. McShane assessed that "the risk of future political intervention in the market is higher than in other Canadian jurisdictions."[99]

CCC, VECC, AMPCO, and CME all took the position that provincial ownership of OPG should be a factor in assessing OPG's risk and in determining the appropriate capital structure.

CCC took the position that the real shareholders are the residents of Ontario, and that the government is acting as their agent or proxy and is responsible for ensuring there is an adequate supply of electricity at reasonable prices:

[99] Ex. C2-1-1, p.64

> The Council submits that the facts require the Board to consider the capital structure and return on equity, not on the basis of what amounts to an artificial concept of a stand-alone entity, but on the basis of the reality that the government, because of its obligations to the residents of the province, has a stake in limiting the risks which OPG faces, and ensuring that OPG does not fail.[100]

CCC noted that the government had directed the OPA to include up to 14,000MW of baseload nuclear generation in its planning, directed OPG to refurbish existing and develop new nuclear capacity, and established a deferral account to recover the costs related to refurbished and new nuclear capacity. In CCC's view, "the government has exercised a power no private sector shareholder has, namely to direct the regulator to ensure risks which are taken in the public interest are protected."[101]

VECC made similar submissions:

> While the identity of any private group of shareholders or owners is not of relevance, ownership of a utility by the same entity that can simultaneously direct utility operations and direct regulatory treatment is of the utmost relevance in this case especially with respect to risk and return.[102]

VECC submitted that three factors reduce OPG's risk in relation to other utilities, especially unregulated generators:

- The requirements imposed on OPG through the MOA to mitigate the Province's financial and operational risk in operating the assets and reducing the Province's risk exposure to its nuclear assets
- The requirements in O. Reg. 53/05 that the Board accept certain amounts from OPG's audited financial statements and provide for recovery of various costs
- The various deferral and variance accounts which increase the probability of recovering unforecast costs

AMPCO submitted that the ownership of OPG affects the risks it bears and should be taken into account by the Board. AMPCO noted that both Standard & Poors' and Dominion Bond Rating Service recognize this in citing ownership of OPG as an important factor in determining OPG's debt rating. AMPCO pointed to the evidence it filed from Mr. Adams and Dr. Murphy, which concluded that the impact of past political

[100] CCC Argument, p. 8

[101] Ibid.

[102] VECC Argument, p. 14.

changes on OPG have been passed on to consumers. AMPCO questioned why, if political uncertainty creates risk for OPG, the shareholder should be compensated for a risk of its own creation. AMPCO concluded that regardless of the Board's findings, if the shareholder is dissatisfied with the risk borne by OPG, it can issue a further Directive to shift the impact to consumers.

CME submitted that Ms. McShane "misapplies the stand-alone principle by ascribing little weight to the risk mitigation effects of the government's ownership of OPG."[103] CME also disagreed with Ms. McShane's assessment of political risk:

> We submit that it is unreasonable to suggest that electricity consumers should pay a higher return because OPG's owner, the Government, might take some action which could harm the shareholder interest the Government holds in OPG. Ratepayers should not be burdened with higher Costs of Capital because the Government might decide to act in a way which causes harm to taxpayers as the ultimate owners of OPG.[104]

In response to CCC, OPG submitted that customers' interests must be kept separate from taxpayers' interest, and that this principle has been recognized by the Board in the past. OPG further submitted that the Province's objective of limiting its risk is no different than any other shareholder's, and that the proposed regulatory framework, including deferral and variance accounts, is a reasonable sharing of those risks and consistent with the approach of other utilities.

OPG argued that Hydro One is as important to the province as OPG and it is permitted to earn a commercial rate of return on a stand-alone basis.

OPG also argued that it was incorrect to claim that the government's legislative power has always been used to benefit or protect OPG. OPG pointed to the price caps of the early 2000s and the original requirement to decontrol a substantial portion of OPG's assets: "It is the very fact that the government can act both in ways to advantage and disadvantage OPG that creates uncertainty – and therefore political risk – in the future."[105]

[103] CME Argument, p. 50.

[104] CME Argument, p. 51.

[105] OPG Reply Argument, p. 14.

OPG also noted Ms. McShane's testimony that the circumstances suggest that the Province is trying to establish an arm's-length company and concluded as follows:

> To proceed on the assumption that the shareholder will intervene to protect OPG as an argument for ignoring the stand-alone principle directly contradicts the province's decision to place OPG's prescribed assets under the independent jurisdiction of the OEB.[106]

Board Findings

The stand alone principle is a long-established regulatory principle and the Board has considered its application in a variety of circumstances. The unique circumstances of OPG, however, are in many ways without precedent. As noted above:

- Both the regulated and non-regulated operations perform the same function (i.e., generate power).
- The owner is the Province.
- The Board's approach to setting the payments now and in the future have in some respects been determined by the Province (through O. Reg. 53/05).

OPG is also different from the other entities the Board regulates in that it is not a natural monopoly.

Risk, in the regulatory context, can be considered to be the magnitude of the range of potential outcomes, with the focus generally being on the potential for an adverse outcome. In other words, the greater the range of potential outcomes, the greater is the risk. The Board is faced with two questions when considering the appropriate application of the stand-alone principle in the assessment of risk for OPG:

- Should OPG's risk be considered lower than other regulated Ontario energy utilities because the Province as owner has substantial control over OPG's risks – either in creating them or in protecting OPG from them (shifting the risk to consumers)? This is the issue of the shareholder impact on a regulated entity's risk.
- Is the political risk higher for OPG's regulated assets than for other regulated Ontario energy utilities? This is the issue of the impact of electricity policy changes on risk.

[106] OPG Reply Argument, p. 16

The witnesses and the parties generally agreed that deferral and variance accounts affect the level of risk and reduce it from what it would otherwise be. Similarly, where O. Reg. 53/05 mandates the recovery of certain costs, it is agreed that this reduces risk. O. Reg. 53/05, and in particular the establishment of various deferral and variance accounts and the requirement that certain types of cost be recovered, operates to transfer risk from OPG to customers. The Board must consider the precise nature of the accounts and determine the impact on risk; this is discussed in more detail later in this chapter.

In summary, some of these protections relate to expenditures before the period of Board regulation (the PARTS account) or to activities beyond the operation of the prescribed facilities (recovery of Bruce costs and new nuclear costs). These do not affect the level of risk for the prescribed facilities in the test period. Some of the accounts are comparable to the accounts of other regulated entities; they have not been stipulated through O. Reg. 53/05 for the test period, but rather have been approved by the Board (the accounts related to tax changes, water conditions, nuclear fuel expense, and ancillary service revenues). OPG also applied for other accounts, which the Board has decided not to approve (OPEB changes and SMO and WT revenues).

Two significant protections related to the prescribed assets have been established by O. Reg. 53/05 and will be ongoing: changes in nuclear liabilities and refurbishment costs. These are significant additional protections which have been established by the government and exceed the level of protection typically granted to a regulated utility.

The Board's conclusion is that these accounts do reduce risk. The Board notes, however, that under O. Reg. 53/05, amounts placed in the deferral and variance accounts after the Board's first order will be subject to a prudence review. These accounts will operate the same way for OPG as they do for other regulated entities, although the breadth of protection is greater.

While OPG's risk is lower due to these accounts, should OPG be considered of even lower risk because the shareholder can control whether OPG's financial risks are borne by the customers or the shareholder? The Board concludes that it should not. To conclude that OPG is of lower risk would be comparable to assuming that, after the Board's first order, the Province will direct the regulation of the prescribed assets, and regulate the distribution of risks between OPG and its customers, beyond the protections already established and assessed for purposes of setting the capital structure. O. Reg. 53/05 is viewed by the Board as setting the baseline for OPG as it enters into a formal regulatory framework; essentially limiting any review of activities in the period prior to the Board's payment setting mandate and requiring protection against forecast error (subject to a prudence review) for certain significant costs going forward. The Board concludes that if OPG is operated at arm's length, then it should be examined in the same way as Hydro One, another energy utility owned by the Province. In other words, Provincial ownership will not be a factor to be considered by the Board in establishing capital structure.

The Board must also consider how it will address the shareholder's ability to control future risk. If the Province transfers risks from OPG to consumers in future, then the Board would need to assess the resulting level of risk and adjust the risk ranking (and possibly the capital structure) accordingly.

OPG suggests that its regulated assets are subject to greater political risk than other energy utilities in the province. The Board does not agree that this is a risk that should be reflected in OPG's cost of capital. All of Ontario's energy utilities are subject to risks arising from changing energy policy. The Province has established cost recovery requirements for utilities in which it has no ownership (for example, the regulations related to smart meter implementation). For example, the Province also required the LDCs to spend the third tranche of their market rates of return on conservation and demand management expenditures. The Board concludes that OPG's exposure to the risks and benefits of Provincial direction regarding expenditures and cost recovery are comparable to that of other regulated utilities.

The Board finds no evidence that OPG's regulated hydroelectric and nuclear facilities will be uniquely exposed. Mr. Goulding's evidence suggests that the risk of political interference is higher for OPG, but precisely because the Province is the owner and may choose to use OPG in a way which would be adverse to OPG's financial interests. It would not be appropriate for the Board to assume that the Province will interfere in the distribution of OPG's risks now that the Board has regulatory authority over OPG; it is consistent therefore to regulate OPG on the basis that the Province will not control OPG's currently regulated facilities in a manner which is adverse to OPG's commercial interests. The stand alone principle leads us to conclude that OPG's financial risks are not lower as a result of Provincial ownership; therefore it is consistent to conclude that political risk is not higher as a result of Provincial ownership.

8.3.3 Regulatory Risk

OPG noted that this is OPG's first application under the Board's regulatory authority. In OPG's view there is no track record of stable or consistent regulation and, therefore, there is regulatory uncertainty about the regulatory end state and OPG's ability to recover its costs. As a result, OPG argued, there is a risk of unintended consequences from specific decisions until there is a track record of consistent, stable regulation.

AMPCO pointed to Ms. McShane's evidence wherein she assumes the Board will regulate OPG the way it regulates other utilities and that the Board will provide OPG with a reasonable opportunity to recover its costs and earn a risk related return. AMPCO concluded that this was inconsistent with the claim that OPG's regulatory risks are higher than for other utilities. AMPCO noted that Dr. Booth and Drs. Kryzanowski and Roberts agreed that OPG did not face higher regulatory risk. Pollution Probe pointed, in particular, to Drs. Kryzanowski and Roberts's testimony that regulatory risk is low in reality because the Board has extensive experience with regulating gas and electric utilities, even if it has not regulated OPG previously. CCC and CME also disagreed that OPG's regulatory risks are higher than for other utilities.

OPG noted that both Ms. McShane and Mr. Goulding recognized the regulatory risk associated with the newness of OPG's regulatory regime. In OPG's view, it is not an issue of the Board's competence or integrity; it is an issue that there is not yet an established track record.

OPG also submitted that it faces operating risk from the fact that it is regulated by the Canadian Nuclear Safety Commission (CNSC) which has powers to make orders, including without a hearing in the event of an emergency, the consequences of which have the potential to impose significant costs on OPG. OPG argued that these powers are a significant factor in the regulatory risk assessment.

Board Findings

The Board finds that there is little evidence to support the conclusion that OPG's regulatory risk is higher than that of other regulated energy utilities because of its new regulatory framework. Hydro One and the electric LDCs were also new to Board determined cost of service regulation, but no evidence was presented that those entities were exposed to higher regulatory risk. It is also important to note that the Board's regulatory process provides ample opportunities to address issues of cost recovery through applications, deferral accounts, and motions to review. These are standard and well established regulatory tools; cost of service is a long established regulatory framework; even incentive regulation is well established.

The Board does accept that there could be some risk associated with the uncertainty of applying cost of service regulation, which is typically applied to natural monopolies, to generation assets in Ontario's hybrid market. However, the Board notes that throughout North America there continues to be rate regulation of generation facilities, and that the traditional models of cost of service or incentive regulation are applied in these circumstances. The Board concludes that the risk is therefore minimal.

The risk with respect to the CNSC is whether OPG would be able to recover the costs arising from CNSC action. The Board does agree that it is a category of costs not faced by other regulated Ontario utilities. However, the Board expects that were such costs to arise, OPG would apply for recovery through an application, as would any other regulated entity faced with a significant cost which it claimed was beyond its control and imposed by a body with the authority to do so. The Board would consider the application in the normal way, including a test of prudence.

The Board concludes that regulatory risk is not a significant factor for OPG and is not materially higher for it than for the other utilities the Board regulates.

8.3.4 Operating Risk

For OPG, operating risk entails outage risk, dispatch risk, non-payment risk and the risk associated with environmental obligations. There was general agreement that electricity generators have greater operational risks than non-generation entities regulated by the Board. It was also generally agreed that OPG's risks were lower than those of merchant generators. Given the proposed continuation of the deferral account covering fluctuations in water availability during the test period for the hydroelectric operations, the focus was largely on OPG's nuclear operations and primarily on the risk related to forced outages and dispatch.

OPG took the position that although much has been made of deferral and variance account protection in this case, most of the accounts are simply reflections of the prohibition against retroactive rate making; i.e., they are designed to ensure the recovery of costs associated with initiatives that were directed, authorized or approved by the government before the introduction of rate regulation by the Board. OPG also noted that operating and production risk is the largest risk it faces as nuclear technology is more complex than other types of generation and is subject to a higher risk of unanticipated costs of repair, and loss of production and revenues.

One of the risks that OPG and Ms. McShane identified is dispatch risk. This is the risk that baseload generation from OPG's regulated assets will not be dispatched because of economic conditions and/or the presence of generators with lower marginal costs. AMPCO submitted that this risk is insignificant and pointed to Ms. McShane's analysis of the Ontario market over the last three years. In AMPCO's view, her analysis shows that even at low levels of demand there is the opportunity for additional baseload capacity to be added without a risk that OPG's regulated assets will not be dispatched. AMPCO also noted the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, both of which concluded that dispatch risk is low. CME supported AMPCO's submissions. In the end, there was limited dispute that dispatch risk for OPG is low.

AMPCO submitted that there appears to be a consensus that the major risk facing OPG is related to the operation of the nuclear units. AMPCO submitted that these risks are largely mitigated: ONFA limits OPG's potential liabilities, as changes in the nuclear liability resulting from changes to the decommissioning reference plan are recovered through a variance and deferral account; other deferral and variance accounts cover unexpected costs related to nuclear regulatory costs and technological changes, and the non-capital costs associated with the Pickering A return to service; and new accounts are proposed to cover variances in nuclear fuel costs, pension costs, and taxes.

AMPCO pointed to the evidence of Dr. Booth as supporting the conclusion that the variance and deferral accounts effectively transfer operational risks to consumers. AMPCO submitted that the remaining operational risks are within the control of management and are not risks for which OPG should be compensated.

CCC submitted that while the nuclear assets are undoubtedly riskier than the hydroelectric assets, many of the risks have been covered off with deferral accounts and the only substantive remaining risks are production and operating risks. In CCC's view, "It is inconceivable that the government would allow OPG to be materially adversely affected by production or operating risks."[107] CCC submitted that these risks can be mitigated by increasing the fixed portion for nuclear payments to 50%.

CME submitted that if the proposed additional variance and deferral accounts and the fixed nuclear payment are approved, then the equity ratio should be reduced to 40% in recognition of the reduction in risk from these mechanisms.

OPG replied:

> It was Mr. Goulding's opinion, shared by Drs. Kryzanowski and Roberts, that OPG's nuclear assets are far more exposed to potential loss of revenues due to operational risk than a transmission or distribution network. The operational risk associated with OPG's prescribed assets is, in fact, the principal risk that faces OPG.[108]

OPG submitted that none of OPG's nuclear production risk is mitigated by a deferral or variance account. OPG argued that Dr. Booth's contention that all of OPG's risks are covered by deferral and variance accounts does not recognize that deferral and variance accounts are a common feature of regulated utilities or that OPG does not have an account to cover nuclear production risk. Further, OPG argued that Dr. Booth had not reviewed the ONFA or analyzed the actual extent of the nuclear liabilities and OPG's risk related to residual unfunded liabilities and the limits on the provincial guarantee cap. In OPG's view it still faces significant exposure to this item, even with the related deferral and variance account.

With respect to the deferral and variance accounts generally, OPG characterized them as being designed to prevent "hindsight re-examinations of historical decisions and commitments made long before the OEB acquired jurisdiction to determine payment amounts."[109] In OPG's view, the most recently established accounts reflect the reality that the Board was not the regulator at the time.

All of the experts acknowledged that the use of deferral and variance accounts reduced risk. Ms. McShane testified that her recommendations were based on the assumption that the proposed variance and deferral accounts are implemented. She estimated that if the new proposed accounts (related to nuclear fuel, OPEBs/Pension costs, and tax

[107] CCC Argument, p. 18.

[108] OPG Reply Argument, p. 17.

[109] OPG Reply Argument, p. 22.

changes/assessments) were not implemented, the increased risk would warrant an upward adjustment to either the equity ratio or the ROE.

OPG argued that the evidence is clear that Ms. McShane's recommendations are premised on the approval of the proposed deferral and variance accounts, and that if they are not approved, the equity ratio and/or ROE would need to be adjusted accordingly. OPG submitted that if the scope of the accounts, including, for example, the Nuclear Liabilities Deferral Account, is reduced, then OPG's risk will increase which would need to be reflected in the cost of capital.

Mr. Goulding testified that the fixed payment component would reduce OPG's business risk and pointed out that this payment structure would not be available to merchant generators nor to the generators under contract with the OPA. Ms. McShane estimated that without the fixed payment component, the ROE would need to increase by about half the increase in the variability, approximately 25 basis points, or the equity component should be increased to 60%.

Board Findings

The Board finds that while the dispatch risk for the regulated facilities is low, the operational and productions risks, particularly for the nuclear assets, are significant. Some of these risks are mitigated by the existing and ongoing deferral and variance accounts, but the accounts do not cover all of the risk, particularly not the risk of forced outages and the corresponding impact on costs and production. The accounts fall into four categories: those not related to the prescribed assets; one which provides for recovery of costs which pre-date the Board's regulation of OPG; those that have been specifically approved by the Board in this decision and are typical of utility variance and deferral accounts; and those which provide extended protection against forecast variance. We will review each in turn.

Some of the accounts and cost recovery protection mechanisms contained in O. Reg. 53/05 do not relate to the prescribed assets. The Board is required to ensure that OPG recovers the costs associated with Bruce and the costs associated with new nuclear build. Although these represent significant shifts of costs and risks to customers, they are not related to the regulation of the prescribed facilities. The Board finds that although these requirements may lower OPG's risk as a corporation, they have no impact on the risks of the prescribed facilities.

One of the accounts relates to circumstances and decisions taken before the period in which the Board has regulatory authority. The PARTS account is related to non-capital expenditures related to Pickering A which pre-date the period of the Board's regulatory authority. No new amounts will be added to this account; it is being maintained as the amounts are recovered over the next four years. The Board concludes that this account has no significant impact on OPG's risk in the test period, as the expenditures pre-date the Board's regulatory authority.

Some of the approved accounts going forward are related to protection against forecast error, namely tax changes, nuclear fuel cost, water conditions and ancillary services. The Board concludes that while these accounts each reduce risk, they are not dissimilar to the accounts of other regulated utilities. The electric LDCs have accounts related to tax changes; the ancillary services account ensures customers receive the full benefit of these revenues; and the nuclear fuel and water accounts, while providing protection against inputs over which OPG has little control, are not large relative to the size of OPG's revenue requirement.

The Board is also required to ensure that OPG recovers the revenue requirement implications of changes in the nuclear liabilities Reference Plan and the costs of the refurbishment of the prescribed nuclear facilities. These represent a more extensive risk protection than might typically apply to a regulated utility. Although the nuclear liabilities are unique to OPG, the deferral account ensures that OPG is kept whole and the impact of any change in the Reference Plan is borne by customers. This protects OPG against a significant risk. The refurbishment account provides protection against forecast variance in non-capital costs; this could be significant given the high levels of project OM&A. While the account also provides protection related to capital costs, these costs will not be included in rate base until the assets are in-service in any event and therefore the account does not provide significant additional risk protection. The requirement for a prudence review continues to provide a measure of protection to customers and ensures that OPG retains some risk.

The Board notes that future accounts may be established which further reduce risk; however, that factor is not determinative of the Board's assessment of the current level of risk. The proposed payment structure would also mitigate some of the risk, but as set out in Chapter 9, the Board has determined that it is not appropriate to include a fixed component in the payment structure.

The Board concludes that OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation (for example, given the risk reduction afforded by some of the deferral and variance accounts). The Board also concludes that it is not appropriate for the shareholder to be compensated for all of the operational risks associated with the regulated nuclear facilities. Under cost of service regulation OPG has the opportunity to forecast production and operating costs and to seek recovery of the associated revenue requirement. The Board concludes that it would not be appropriate for shareholders to be fully compensated for the risk that those forecasts are incorrect given that management controls the development of the forecasts and has some considerable control over the achievement of those forecasts.

8.3.5 Capital Structure Conclusion

CCC concluded that OPG was no riskier than any other utility and that Dr. Booth's recommended equity ratio of 40% was appropriate. Similarly, AMPCO took the position that OPG and Ms. McShane have exaggerated the risks facing OPG and concluded that the equity ratio should remain unchanged. SEC submitted that the equity component should be 47%, representing 40% for hydroelectric and 50% for nuclear. OPG replied that those who have recommended lower equity ratios than Ms. McShane have underestimated OPG's business risk.

Board Findings

Union Gas Limited and Enbridge Gas Distribution Inc. both have equity ratios of 36%, and the risk differential between Union and Enbridge is reflected in Union's ROE which is 15 basis points higher. The electric LDCs and Hydro One have equity ratios of 40%, and Great Lakes (transmission) has an equity ratio of 45%. The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation. And while the deferral and variance accounts mitigate some aspects of OPG's risk, they do not protect against outage risk.

The Board finds that the proposed equity ratio of 57.5% is excessive. The incremental level of risk does not warrant the additional 12.5% equity over that of the next highest regulated utility. It is also well in excess of the equity levels of merchant generators, who have higher risk than OPG, as pointed out by Mr. Goulding. The Board concludes that the recommendation of Drs. Kryzanowski and Roberts, namely an equity ratio of 47%, is appropriate in the circumstances. This ratio is higher than the equity ratio of any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG. The Board notes that this deemed capital structure will be applied to the rate base which is net of the specific treatment to be applied to the nuclear liabilities related to Pickering and Darlington (which is discussed in Chapter 5).

8.4 Return on Equity

8.4.1 Introduction

Ms. McShane used three tests: the Equity Risk Premium ("ERP") test, the Discounted Cashflow ("DCF") model test and the Comparable Earnings ("CE") test. For the ERP test, she used three approaches:

- Capital Asset Pricing Model ("CAPM")
- Historical utility risk premium test
- Discounted Cash Flow ("DCF") risk premium test

Although Ms. McShane updated her estimates of the various tests in April 2008, the result was no change in the aggregate ROE recommendation: in her view, the lower government interest rate is partially offset by a higher risk premium which is reflected in a higher spread between government bonds and long-term A-rated utility bonds.

Pollution Probe submitted that the Board should prefer and accept the recommendations of Drs. Kryzanowski and Roberts. They used four methods to estimate the market equity risk premium: the Equity Risk Premium (including CAPM) methodology and three other methods to support the "directional conservatism" of the estimate derived from the ERP method. Pollution Probe noted that OPG acknowledged that this was now the dominant methodology used for regulated energy utilities in Canada.

CCC submitted that the Board should prefer the testimony of Dr. Booth to that of Ms. McShane. Dr. Booth estimated that OPG will have sufficient financial flexibility to access capital markets on reasonable terms with an ROE of 7.75% and an equity ratio of 40%. Dr. Booth relied on a CAPM risk premium model and a two-factor model, with the CAPM estimate based on an historic average market risk premium adjusted for the changing risk profile of the long Canada bond, and the two factor model taking into account the interest rate sensitivity of utility stocks.

CCC noted that the average return on the Canadian equity market has been 10.42% over the period 1924-2007 and that current allowed ROEs are generally less than 9% for utilities on a formula mechanism. CCC submitted that Ms. McShane's recommendation of 10.5% ROE on a 57.5% equity ratio implies that OPG's risk exceeds that of other regulated Canadian assets by a considerable margin. In CCC's view, there is no factual basis for this view. VECC supported CCC's submissions.

SEC submitted that the critique by Drs. Kryzanowski and Roberts of Ms. McShane's evidence and the cross-examination of Ms. McShane, which revealed the utility-side biases in her evidence, lead to the conclusion that her evidence is not credible and should not be relied upon by the Board. SEC also expressed concern with Dr. Booth's continuing view that Canadian allowed utility ROEs are too high, due to incorrect analysis by regulators of the risk mitigation effect of the ROE method being used, and noted that this conclusion has generally not been accepted. SEC concluded that Drs. Kryzanowski and Roberts' evidence was the most thorough and rigorous, and should be adopted by the Board in setting ROE.

OPG submitted that there was a fundamental contradiction in the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, in that both recognized that OPG was of higher risk than other Canadian utilities, yet both made recommendations for ROE below that of any regulated Canadian utility.

First, the Board will address the alternative approaches to setting the ROE proposed by CME, AMPCO, and Dr. Schwartz and Energy Probe. We will then turn to a discussion of the various analytical tools used by Ms. McShane, Dr. Booth and Drs. Kryzanowski and Roberts.

8.4.2 Alternative approaches (CME, AMPCO, Dr. Schwartz and Energy Probe)

AMPCO submitted that the use of CAPM and DCF models is inappropriate for OPG's heritage assets.

> AMPCO submits that OPG is a financial hybrid with a government-assigned ROE reflective of its character as a government-owned, but commercially structured body. In AMPCO's view, the initial conditions established in O.Reg. 53/05 were well considered at the time of issuance and remain appropriate…The setting of the ROE was a fair solution that recognized the role consumers had played in assuming stranded debt obligations while at the same time providing for OPG's financial needs.[110]

In AMPCO's view, the current ROE has not prevented OPG from undertaking capital projects and the credit rating agencies have indicated that OPG's financial performance has improved under the current arrangements. AMPCO concluded that "the ROE should be set to the true cost to the shareholder of having assumed this segment of OPG's debt obligation to the OEFC, namely the interest rate on this debt, which is 5.85%."[111]

CME submitted that the ROE should be between 5.85% and 8.57% (the most recently approved level for Hydro One), and should be set at the lower end of the range given the acknowledgement by the government in its February 23, 2005 announcement that the 5% ROE ensures a fair return to taxpayers.

OPG responded that a return of 5.85% violates the stand-alone principle, regulatory principles, and finance principles:

> CME and AMPCO miss the central point: that the return the government or any other investor would expect from its investment is one that reflects the riskiness of the project it is investing in, not the cost incurred to raise the capital for the investment.[112]

OPG also pointed to Mr. Goulding's testimony that "OPG should not be compelled by the regulator to suppress what would otherwise be just and reasonable equity returns to serve other policy objectives."[113] With respect to the upper bound of CME's proposed range, OPG responded that OPG's ROE should be no less than Hydro One's.

In applying the CAPM test, Dr. Schwartz used a Treasury bill rate (3.24%) and estimated the equity market risk premium at 6.7% over the Treasury bill yield. He

[110] AMPCO Argument, p. 29.

[111] AMPCO Argument, p. 31.

[112] OPG Reply Argument, p. 11.

[113] Tr. Vol. 12, pp. 111-112.

adjusted this premium by the 0.65 adjusted beta (the median of Ms. McShane's range for the median Canadian utility). Dr. Schwartz's evidence was that the long-term bond yield overstates the risk free rate unless the premium for holding a longer-term instrument is removed.

Energy Probe submitted that the test of whether Dr. Schwartz's recommendations are more appropriate than Ms. McShane's is whether the ROE and capital structure "produce a plausible and reasonable estimate of fair market asset value."[114] Energy Probe submitted that Ms. McShane's recommendations support a fair market value of $6.2 billion, which is below book value, and hence results in the shareholder being over-compensated. Dr. Schwartz's recommendations support a fair market value of $9.9 billion, or 1.3 times book value, which is more reasonable in Energy Probe's view.

SEC submitted that Dr. Schwartz's evidence was of limited value given his unfamiliarity with the standard regulatory approach. Although a private sector analysis of OPG would be a useful approach, SEC submitted that "the expert will still have to be able to articulate the differences between that fresh, private sector point of view, and the regulated entity point of view that it is proposed to supplant."[115]

Board Findings

The Board agrees with OPG that it would be inappropriate to set OPG's ROE at 5.85%. This rate does not represent the cost of capital for OPG's regulated facilities; it is the interest rate on OPG's prior debt obligation to the OEFC. The Province may have assumed this debt, but that is related to the shareholder's cost of capital, not OPG's cost of capital.

The Board finds while it is relevant to consider Hydro One's ROE, and the ROEs of other regulated utilities, they are not determinative of the appropriate ROE for OPG. It is appropriate to determine OPG's ROE using the standard tests for establishing a benchmark return. This reflects the Board's long-standing approach to these issues.

The Board concludes that while Dr. Schwartz presented novel ideas, he was unable to address his recommendations within a regulatory context. As a result, the Board did not rely on his evidence for purposes of setting the cost of capital.

[114] Energy Probe Argument, p. 18.

[115] SEC Argument, p. 7.

8.4.3 Review of standard tests for establishing a benchmark return

The Discounted Cashflow ("DCF") Test

PWU noted Ms. McShane's testimony that the DCF test has the advantage of estimating the cost of equity directly because it relies on analysts' projections. PWU pointed to Ms. McShane's testimony that her examination of the analysts' forecasts back to 1993 (for the DCF risk premium test) found the average forecast was about 60 basis points lower than the consensus forecast for economic growth, concluding there is no reason to believe investors would view analysts' estimates as systematically optimistic.

Pollution Probe noted the testimony of Drs. Kryzanowski and Roberts to the effect that the DCF model is more appropriately used at the level of the overall market, rather than the firm or industry level. Pollution Probe also submitted that Ms. McShane has not adjusted the results for the bias in analyst forecasts: "This bias is widely documented for samples that include utilities, and, absent evidence showing that the bias does not apply to utilities, there is no reason why an adjustment should not have also been made in this case."[116]

CCC noted that Dr. Booth used the DCF method (estimating a DCF return for the market as a whole) as a check only, because of the endemic data problems and the lack of pure play utilities. CCC pointed to Dr. Booth's testimony that the latest research indicates the forecast bias at an average of 2.84% and that Ms. McShane's estimates have not been adjusted for this bias.

OPG responded that there was no need to make an adjustment for optimism bias because there was no evidence or reason for such a bias in the utility context. OPG also noted that the DCF test is the one relied on by US regulators who would presumably be aware of this alleged optimism bias but continue to find the DCF test, based on the analysts' forecasts, compelling.

Comparable Earnings Test

Pollution Probe noted Drs. Kryzanowski and Roberts' criticisms of the CE test and maintained that the Alberta Utilities Commission gives no weight to the CE test. Pollution Probe submitted that "when common finance tests are applied, the rate of

[116] Pollution Probe Argument, p. 6.

return in Ms. McShane's sample abnormally outperforms the S&P/TSX Composite, especially given that this sample represents firms with low risk relative to the market."[117] Energy Probe also submitted that the Board should disregard the CE test approach.

CCC noted Dr. Booth's testimony that while it is appropriate to examine the returns of Canadian companies to establish where we are in the business cycle, it is not appropriate to use this data to establish a fair ROE.

OPG responded that all of the tests have their drawbacks, but the CE test is useful in the context of the fair return standard as a measure of fair return based on the concept of opportunity cost. OPG noted that some of the criticisms of the CE test by Drs. Kryzanowski and Roberts (disagreements as to the appropriate time period and treatment of structural changes in the economy, and the fact that the rates are backward looking) are equally applicable to the CAPM. OPG maintained that formula returns driven by the CAPM test alone are too low.

Equity Risk Premium ("ERP") Test

The ERP test considers three factors: the long-term risk free rate, the market equity risk premium, and the relative risk adjustment for a benchmark Canadian utility (or beta coefficient). There was some disagreement amongst the experts as to the forecast of the risk free rate, but the differences were more marked in relation to the estimation of the market equity risk premium and the appropriate beta coefficient. These differences result in material differences in the recommendations. AMPCO noted that having started with essentially the same data, Ms. McShane ends up with a much higher "bare bones" ROE recommendation of 9.25%-10.25% than Dr. Booth (7.25%) or Drs. Kryzanowski and Roberts (6.35% and 6.75% for 2008 and 2009, respectively).

Ms. McShane estimated the market risk premium at 6.5%; Dr. Booth and Drs. Kryzanowski and Roberts estimated it to be 5%. AMPCO submitted that the evidence based on Canadian data over long time periods indicates a market risk premium of 4.5%-5.5%, and that a shorter time period yields a lower market risk premium.

OPG noted that achieved equity returns have remained relatively constant. This, coupled with increasing long Canada returns, has tended to shrink the achieved market equity risk premium. Forecast long Canada yields are much lower, and therefore, in

[117] Pollution Probe Argument, p. 7.

OPG's view, Drs. Kryzanowski and Roberts' estimate is downwardly biased: "They have not given sufficient recognition to market equity risk premium increases resulting from lower anticipated bond market returns."[118]

OPG submitted that Dr. Booth's evidence regarding government budgets and the bond market supports a conclusion that bond returns in the future are expected to be lower than historically. OPG concluded that "the Canadian equity risk premium under current capital market conditions is higher than the observed risk premium."[119] OPG concluded that the equity risk premium must be substantially higher than Dr. Booth's estimate of 5%, and must be at least 6.5% if equity returns remain stable at 11.2%-11.6% and the forecast yield on government bonds is 4.5%.

While both Dr. Booth and Ms. McShane use adjusted betas for the relative risk adjustment, they adjust their beta data differently. Ms. McShane adjusted the betas to estimate a relative risk adjustment of 0.65-0.70; Dr. Booth and Drs. Kryzanowski and Roberts estimated the adjustment to be 0.50.

CCC submitted that because Ms. McShane adjusts the raw betas by averaging them with 1.0, they are generally increased because utility betas are almost always less than 1.0. Dr. Booth also adjusts his beta estimates upwards, but based on recent market conditions.

AMPCO pointed to the evidence of Drs. Kryzanowski and Roberts and Ms. McShane which indicate a downward trend in beta. AMPCO noted Ms. McShane's adjustment to correct for interest sensitivity of regulated utilities introduces a bias towards the value of one, whereas Dr. Booth and Drs. Kryzanowski and Roberts's adjustments for the same issue do not alter their beta estimates significantly.

OPG responded that Dr. Booth and Drs. Kryzanowski and Roberts's betas are too low and maintained that use of adjusted betas "recognizes that 'raw' utility betas do not adequately explain utility returns; their use mitigates the deficiencies in raw betas as a predictor of future returns."[120] Dr. Booth and Drs. Kryzanowski and Roberts only adjusted their betas by taking averages of 'raw' betas, which is not the appropriate adjustment in OPG's view.

[118] OPG Reply Argument, p. 28.

[119] OPG Reply Argument, p. 29.

[120] OPG Reply Argument, p. 31.

Board Findings

It is important to emphasize that the establishment of the ROE is for purposes of the prescribed assets only; it is not related to OPG's unregulated businesses, nor is it related to attracting capital for new generation build which is unregulated.

The Board finds that each of the analytical tests has value as each provides a different perspective on the question of the appropriate ROE. However, each test also has its weaknesses. For example, there is evidence of analyst bias, which although not conclusive with respect to utilities, suggests that the DCF cannot be relied upon wholly. These weaknesses were highlighted during the testimony of the experts and in references to other studies in the financial literature. In all cases, significant judgment is brought to bear by the experts because historical data are being used to estimate the future. In addition, the data may not be sufficiently comparable; if, for example, it is U.S. data, or there may be varying time periods under consideration. As Ms. McShane acknowledged, each test is a "blunt instrument."[121]

The Board concludes that the various expert recommendations provide the reasonable range of results, but the extremes of the range (both highest and lowest) should not be adopted given these inherent limitations in the methodologies.

The Board concludes that the ERP test is the most reliable test upon which to base its determination. The Board has the benefit of having had a number of experts develop their recommendations based on this approach. As noted above, each test includes important elements upon which the expert must apply judgment. For the ERP test, judgment is applied in determining the appropriate adjustment to the raw betas and in estimating the appropriate market equity risk premium. The Board accepts that an upward adjustment of the raw betas is warranted, and, similarly, that changes in the anticipated bond yields may require an adjustment to the observed market equity risk premium. However, the Board concludes that no particular approach by a single expert is wholly reliable. The Board considers it reasonable to consider the range of risk premiums in determining the appropriate level, but neither extreme of the range is appropriate. The estimates of the risk premium range from about 2.5% to over 5%, although these are applied to different forecasts of the risk free rate. The Board concludes that a risk premium of 3.4% is appropriate in the circumstances, based on the Board's judgment of the evidence before it and the previously discussed factors.

[121] Transcript Vol. 10, p. 17.

Using a forecast long-term risk free rate of 4.75% and a risk premium of 3.4%, the resulting “bare bones” ROE would be 8.15%.

8.4.4 Adjustment for financing flexibility

The purpose of adding an adjustment for financing flexibility to the “bare bones” cost of equity is to compensate the utility for potential equity flotation issuance costs and to protect the financial integrity of the utility against any adverse impacts from potential unexpected events in the capital markets and the economy.

Energy Probe submitted that adding 50 basis points for financial flexibility was unwarranted as OPG will not issue shares and therefore requires no compensation for floatation costs. AMPCO agreed with Dr. Schwartz that the reasons given for adding 50 basis points for financial flexibility are unconvincing: all of OPG’s borrowing will be from the OEFC and there is no expectation that equity will be raised in the test period.

OPG responded that the 50 basis point allowance does not turn on whether the utility is actually forecast to enter the market or not. It is a margin for unanticipated market conditions and “recognizes the basic principle of regulation, that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value.”[122] OPG maintained that this principle is well established and noted that Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane all included the provision and that it has been included in setting the ROE for Hydro One and the electricity LDCs.

Board Findings

The Board will include this adjustment of 50 basis points. The adjustment has been used in the past and forms part of the recommendations made by Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane. Adding 50 basis points to the “bare bones” ROE of 8.15% results in an ROE of 8.65%. The Board concludes that this result is also reasonable because it is comparable to the levels of return allowed to other Ontario regulated energy utilities, and although OPG is of higher risk, that risk has been recognized through the higher equity ratio.

[122] OPG Reply Argument, p. 35.

8.4.5 Should there be separate costs of capital for regulated nuclear and regulated hydroelectric?

GEC-Pembina-OSEA took the position that OPG should recognize the higher risks of the nuclear business in its capital and OM&A expenditure decisions. GEC-Pembina-OSEA sponsored the evidence of Mr. Paul Chernick on this issue. GEC-Pembina-OSEA concluded:

> The Board should select an acceptable combined cost of capital (with the deferral accounts it finds acceptable in place) and then adjust the nuclear division equity ratio and RoE upward and make a corresponding balancing downward adjustment to the hydraulic division values in accord with Ms. McShane's estimates.[123]

GEC-Pembina-OSEA submitted if the Board does not set a separate cost of capital for each division, then the Board should direct OPG to use project-specific discount rates to reflect the relative risk level. GEC-Pembina-OSEA also suggested that in a future proceeding it might be appropriate to consider Mr. Chernick's proposal that deferral accounts be minimized, that the risk be reflected in the cost of capital, and that the added revenue be segregated to mitigate those risks if they arise.

Pollution Probe submitted:

> For purposes of cost allocation and rate design, separate and distinct costs-of-capital should be used since: 1) the nuclear assets are riskier than the hydro assets; and 2) OPG is already proposing different charges per MWh for its nuclear and hydro-electric assets [due to separate costs of production].[124]

Pollution Probe noted OPG's testimony that it did not object to this approach in principle, although it expressed concern as to whether such an approach was pragmatic in terms of the necessary calculations. Pollution Probe was of the view that the Board has the necessary evidence for such an approach and submitted that the evidence of Drs. Kryzanowski and Roberts should be accepted as they did determine separate capital structures for nuclear and hydroelectric as part of their analysis.

[123] GEC-Pembina-OSEA Argument, p. 7

[124] Pollution Probe Argument, p. 2.

SEC submitted that there would be value in setting separate capital structures in terms of reviewing investment decisions, but noted that the nuclear costs are not "real" in any event because the liabilities were shifted from OPG when it was created. SEC concluded that whether or not the Board sets separate structures,

> …it should direct OPG to maintain records of the relative costs of production and investment using separate equity ratios, and to carry out business case and similar forward-looking expenditure analyses using those technology-specific equity ratios.[125]

SEC submitted that the same ROE should apply to both, because the difference in risk is appropriately captured through the equity ratio.

CME submitted that there was no need to set separate capital structures for the nuclear and regulated hydroelectric when they are operated by a single business entity.

OPG responded that alleged benefits of technology-specific cost of capital either do not exist or are insignificant. For example, there is no evidence that a higher nuclear payment amount would impact operating decisions, and OPG already has a strong incentive to meet its production targets. Further, OPG's project specific risk analysis provides more rigour than a technology-specific discount rate would.

Board Findings

Although the regulated hydroelectric and regulated nuclear businesses are held by the same entity, in many respects they are operated quite separately. The rate base is separate; the production forecasts, capital budgets and OM&A forecasts have been established separately; the corporate cost allocation is done separately; and the payments are set separately. The two businesses also face different risks. The Board finds that there may be merit in establishing separate capital structures for the two businesses. It would enhance transparency and more accurately match costs with the payment amounts.

However, the Board also finds that the evidence in this proceeding is not sufficiently robust to set separate parameters at this time. Drs. Kryzanowski and Roberts developed separate estimates, but concluded with a combined recommendation. Ms.

[125] SEC Argument, p. 9.

McShane developed separate estimates, but cautioned that she was not as confident with the analytical results because they had been derived from working backwards.

The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs or the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs.

8.4.6 Should the Board adopt a formula to determine the ROE in future?

OPG proposed that the Board adopt an ROE adjustment formula for purposes of determining OPG's ROE in future proceedings. Specifically, OPG proposed adoption of the existing ROE adjustment formula outlined in the Board's report on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors.[126] That formula results in a 75 basis point change in ROE for every one hundred basis point change in the 30-year Long Canada Bond forecast.

OPG noted that it would seek a review of the formula returns if its business risk or access to capital changed materially and submitted that the adoption of a formula should not preclude it or another party from seeking a review. SEC supported the use of Board's formula approach to adjusting the ROE for years after 2009. CME also submitted that the formula approach was reasonable.

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[126] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* December 20, 2006.

Board Findings

The Board agrees that adoption of a formula approach to setting the ROE is appropriate in the circumstances. The Board will adopt the existing ROE adjustment formula outlined in its report on cost of capital and 2nd generation incentive regulation for purposes of determining OPG's return on equity. The Board intends to examine whether the regulated hydroelectric and nuclear businesses should have separate capital structures. Setting the ROE through a formula is consistent with the Board's expectation that risk differences in the regulated businesses are appropriately addressed through the capital structure rather than the ROE.

8.5 Cost of Debt

8.5.1 Short-term debt

OPG forecast the cost of short term debt at 5.83% for 2008 and 5.98% for 2009.

AMPCO submitted that OPG's short-term rate on commercial paper of 8.4% appears excessive given the prime corporate paper rate was 3.17%. AMPCO also submitted that OPG's cost for Account Receivable securitization of 5.54% appears to be above current short-term rates. AMPCO submitted that a target cost of about 4% is more consistent with current conditions. SEC and CME supported AMPCO's submissions.

OPG responded that it uses commercial paper and Account Receivable securitization as its main source of short-term financing, but it also has a bank credit facility that has a forecast $1.4 million fixed cost. OPG noted that AMPCO had inappropriately rolled in this fixed cost with the forecast cost of commercial paper to derive its "implicit cost rate" of 8.4%. The rates on commercial paper are forecast to be 5.13% in 2008 and 5.32% in 2009, based a forecast of bankers' acceptances rate, the corporate spread and the dealer fee. OPG concluded its proposed short-term debt rate was reasonable as it is based on independent forecasts.

Board Findings

The Board will accept OPG's forecast cost of short term debt. The rates are based on independent forecasts. The Board finds that there is no evidence to support AMPCO's proposed level of 4%; that level is derived from an examination of then-current market conditions, not an assessment of conditions over the test period.

8.5.2 Long-term debt and the "other" long-term debt provision

OPG noted that its long-term debt outstanding with the OEFC is comprised of financing for unregulated projects, corporate debt of $3.2 billion and Niagara Tunnel project debt of $240 million. OPG added that about $1.6 billion in new borrowing is needed over the test period. OPG allocated its existing and planned corporate debt issues to regulated and unregulated operations using the ratio of *regulated* net fixed assets at December 31, 2007 to the *total* net fixed assets as per OPG's 2007 audited financial statements. (Project-related debt is assigned directly.) The forecast cost of planned new and refinanced corporate debt and project-related debt for 2008 and 2009 is based on the December 2007 Global Insight forecast of the 10-year Long Canada Bond plus an OPG credit margin of 130 basis points.

This allocation of OPG's existing and planned debt is not sufficient to equate OPG's proposed rate base with its proposed deemed capital structure. The "other" long-term debt provision – or "plug" – is the difference between the debt needed to equate the proposed deemed capital structure to the proposed rate base and the allocated debt. The interest rate attributable to this debt is the "average unhedged interest rate of new and refinanced debt issued each year for both corporate and project-related borrowing purposes."[127]

OPG forecast its long-term debt rates as 5.79% across the test period for its existing and planned long-term debt, and as 5.65% in 2008 and 6.47% in 2009 for its "other" long-term debt.

AMPCO submitted that the allocated existing long-term debt and the project-related debt were determined in a reasonable way and that the costs, being the actual rates paid, were acceptable. AMPCO submitted, however, that the proposed rates for new long-term debt of 5.65% in 2008 and 6.47% in 2009 are too high. AMPCO pointed out that OPG has proposed a credit risk spread of 130 basis points but the evidence is that OPG paid a spread of only 74.25 basis points on the Niagara Tunnel financing.

AMPCO submitted that applying a spread of 75 basis points to an average 10-year Canada rate for 2008 and 2009 of 4.25% would result in an interest rate of 5.0%. AMPCO recommended that a rate no higher than 5.5% be used for 2008 and 2009.

[127] OPG Argument in Chief, p. 37.

AMPCO further submitted that the Board's principle that in the case of long term debt held by an affiliate a utility shall only recoup the lower of the negotiated rate or market rate should apply to OPG as well. SEC and CME supported AMPCO's submissions.

OPG disagreed with AMPCO's forecast long term debt rate of 5.5%. OPG submitted that the 75 basis point spread available in June 2007 is not expected to be available under market conditions in the test period. The evidence is that spreads have widened and are expected to remain higher. OPG's most recent spread is 168 basis points, even higher than the spread of 130 basis points underpinning its proposed debt rate. OPG maintained that AMPCO's forecast 10 year Canada rate is also understated and that OPG's forecast was based on an independent forecast by Global Insight.

With respect to the affiliate argument, OPG responded that its arrangements with OEFC use an estimate of market rates derived through objective and independent information.

Energy Probe relied on the evidence of Dr. Schwartz and submitted that the "other" long-term debt provision should be accounted for as equity instead, and that the interest expense associated with the plug should be removed. Energy Probe submitted that using equity for the plug would result in an unacceptably low debt/equity ratio and that therefore the additional equity should be assigned a return of 0%. Energy Probe noted that this approach would not be necessary if the prescribed assets were transferred to a subsidiary with an approved capital structure.

Board Findings

The Board accepts OPG's proposed rates for 2008 and 2009 for existing and planned debt. The Board does not agree with AMPCO's conclusion that the cost of new debt should be set at 5.5%. The forecast costs of the planned debt are based on independent forecasts. The Board also accepts OPG's evidence that the credit spreads have widened and the spread available in June 2007 is not expected to be available in test period. Further, the Board accepts OPG's evidence that the OEFC rate is designed to be a market rate.

The Board finds, however, that the method for setting the cost of the "plug" debt is not appropriate. Rather than using the average of the unhedged cost planned debt, as OPG proposed, the Board finds that it is appropriate to use the average of the hedged cost of planned debt. This results in a forecast cost of debt for the "plug" which is consistent with the forecast cost of the allocated debt. On this basis, the cost of long-term “other” debt will be set at 5.63% for 2008 and 6.16% in 2009.

The Board will not adopt the approach suggested by Energy Probe. The Board has already noted that it did not rely on Dr. Schwartz’s evidence.
The Board’s decision with respect to the treatment of the unfunded nuclear liabilities for Pickering and Darlington will affect OPG’s allocation of existing long-term debt and the level of “other” long-term debt. The Board does not have sufficient data to determine these impacts and therefore directs OPG to perform these calculations as part of the draft order.

9 DESIGN AND DETERMINATION OF PAYMENT AMOUNTS

9.1 Tax Losses and Rate Mitigation

OPG proposed to reduce the test period revenue requirement by $228 million because it "recognizes that the revenue requirement increase over the current payment amounts is significant and will have an impact on electricity consumers."[128] OPG characterized this mitigation as an acceleration of the application of regulatory tax loss carry forwards that OPG claimed existed at the end of 2007 and that would not be utilized in 2008 or 2009.

OPG said its regulatory tax losses at December 31, 2007 were $990.2 million. It forecast that $487 million of that amount would be used in 2008 and 2009, leaving $503.2 million available for subsequent periods.[129]

In addition to this mitigation, OPG decided not to recognize any provision for payments in lieu of income taxes (PILs) in the test period. PILs payments are calculated in accordance with federal and Ontario tax laws but are paid to the Ontario Electricity Financial Corporation. Assuming the Board were to approve its application as filed, OPG estimated that its regulatory taxable income, before consideration of the regulatory tax losses, would be $487 million for the two years ended December 31, 2009. At currently enacted tax rates, the PILs payments would be approximately $150 million for that period. The amount of PILs for the 21-month test period related to the prescribed facilities would be lower than that amount but would still be quite substantial.[130]

OPG calculated the accumulated "regulatory tax losses" of $990.2 million at the end of 2007 by computing the taxable income or loss since April 1, 2005 of the prescribed facilities (plus the Bruce lease). OPG indicated that the main reasons for the regulatory tax losses were:

[128] Exhibit K1-1-2, page 1.

[129] Exhibit F3-2-1, Table 9.

[130] The Board was not able to calculate even a rough estimate of the amount of PILs for the test period for the prescribed facilities because regulatory taxable income as calculated by OPG includes taxable income related to OPG's Bruce lease. Also, the 2008 PILs amount provided by OPG is for a full year, not nine months.

- OPG made substantial tax-deductible contributions to the segregated nuclear funds (contributions during the period were $888 million, including a special one-time payment of $334 million in 2007 related to the Bruce facilities);
- the deduction in 2005 of $258 million in Pickering A return to service costs; and
- a loss before income tax from the prescribed facilities in 2007.

OPG referred to its accumulated loss carry forwards as "regulatory tax losses" to distinguish them from actual tax loss carry forwards that are recognized by the tax authorities. In fact, OPG's witnesses noted that OPG did not have any actual tax loss carry forwards at the end of 2007. The benefit of all tax losses that were generated by the prescribed facilities during the period 2005 to 2007 were used to reduce PILs payable by OPG in respect of its unregulated operations. OPG's witnesses also noted that in its consolidated financial statements for 2005 through 2007, OPG recorded the benefit of those "regulatory tax losses" in earnings; it did not credit any of the benefit of those losses to a deferral account to be used to reduce the payment amounts for the prescribed assets after April 1, 2008.

In its argument, OPG submitted that: "While an argument could be made that these tax losses belong to OPG and not to ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is appropriate that they be returned to ratepayers."[131]

Only a few intervenors commented on OPG's proposed mitigation and its elimination of a tax provision for 2008 and 2009. CCC, CME and SEC supported OPG's approach. CCC and SEC noted that, absent the mitigating effect of the tax losses, the increase in payment amounts sought by OPG would be much higher than proposed in its application. CME supported OPG's approach and noted that OPG was not obliged to allocate the benefit of the prior period tax losses to consumers.

Board Findings

OPG's proposals to exclude a tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million mitigation amount are both linked to the $990.2 million of "regulatory tax losses" that OPG claims existed at December 31, 2007.

[131] OPG Argument-in-Chief, page 109.

OPG's tax calculations did not receive much scrutiny during this proceeding. Although intervenors supported OPG's proposals (or were silent on the issues), the Board is not convinced that OPG has taken the right approach to income tax issues in its application.

The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct. Reasons for the Board's concerns about OPG's treatment of taxes include:

- OPG's calculation of regulatory tax losses for 2005 to 2007 includes revenues and expenses related to OPG's Bruce lease. The Bruce stations are not prescribed facilities and OPG's Bruce lease is not regulated by the Board. In the Board's view, any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease.[132]
- OPG did not have any tax loss carry forwards at the end of 2007. OPG's witnesses confirmed that OPG was able to use the tax losses generated by the prescribed facilities for period 2005 to 2007 to reduce the income taxes that OPG would otherwise have paid in respect of its unregulated businesses. That is, the benefit of the tax losses related to OPG's regulated assets for 2005 to 2007 has already been realized by OPG.
- OPG witnesses confirmed that the benefit of the pre-2008 tax losses in respect of the regulated assets was recorded in OPG's audited financial statements in the form of a lower tax expense. Those witnesses also confirmed that OPG did not establish a deferral account at the end of 2007 to capture the tax benefits it claimed should be used to reduce regulatory taxes for 2008 and later periods in its application. The treatment of tax losses adopted in OPG's financial statements appears to conflict with the position taken in OPG's application to the Board.
- OPG stated that an argument could be made that the regulatory tax losses belong to OPG and not to customers since they arose in a period prior to Board regulation. Nonetheless, OPG submitted it was appropriate that the tax benefits be credited to customers although it offered no reasons why it was considered to be appropriate.

[132] As noted in Chapter 8, the Board has determined that revenues and costs related to the Bruce stations should be calculated for purposes of section 6(2)10 of Regulation 53/05 in accordance with GAAP (not regulatory accounting) and that a tax provision should be included in the Bruce costs.

Although the Board is not convinced that regulatory tax loss carry forwards existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all of the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.

The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss.

- In 2005, OPG deducted $258 million of Pickering A return to service costs in computing taxable income for that year. For accounting purposes, OPG recorded those costs in the PARTS deferral account. As noted in Chapter 7 of this decision, the remaining deferral account balance at December 31, 2007 of $183.8 million will be recovered through future payment amounts for the nuclear facilities. In the Board's view, the majority of the tax benefit realized by OPG in 2005 should be for the account of consumers given that the nuclear revenue requirement after 2007 will include $183.8 million to recover the deferral account balance.
- OPG's evidence indicated that in 2007 its regulated operations incurred an $84 million loss before income taxes (how much of that loss, if any, that relates to Bruce is unclear). It would appear that the operating loss in 2007 was borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.

The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods. The Board has therefore examined the proposed level of mitigation within the context of OPG's overall application.

With respect to 2008 and 2009, the Board is not able to agree, for the reasons outlined above, with OPG's position that "regulatory tax losses" permit it to eliminate an income tax provision. Because there is no evidence about the amount of pre-2008 tax benefits that appropriately should be carried forward to offset 2008 and 2009 PILs, the Board views OPG's proposal to eliminate an income tax provision in the test period as simply mitigation. OPG has effectively agreed to absorb whatever tax provision would otherwise be required for those years. The Board finds that this mitigation should be retained in OPG's calculation of the revenue requirement and payment amounts that flow from the Board's findings in this decision. That is, OPG should not include any tax provision for 2008 and 2009 in respect of the prescribed assets.

As for OPG's proposed $228 million mitigation amount, the Board also does not accept that there is any connection between that amount and any regulatory tax losses. OPG's offer of $228 million of mitigation was made in the context of the revenue requirement, before mitigation, shown in OPG's application. The revenue requirement that results from the Board's findings in this decision will be lower than that proposed by OPG. The Board concludes that it would be unreasonable to hold OPG to its original offer of mitigation. The mitigation amount of $228 million was about 22% of the $1,025.7 million revenue deficiency shown in OPG's application. The amount of mitigation the Board will require OPG to provide for the test period will be equal to 22% of the revenue deficiency calculated based on the Board's findings in the decision. The Board estimates that this amount will be about $170 million, compared to the $228 million in OPG's application.

In its next application for payment amounts for the prescribed assets, the Board will require OPG to file better information on its forecast of the test period income tax provision. To that end, the income tax provision for the prescribed facilities in future applications should not include any income or loss in respect of the Bruce lease. The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. That analysis should be based on the principle that if OPG is proposing that electricity consumers should bear a cost (or should benefit from revenues) they will receive the related tax benefit (or will be charged the related income taxes).

The Board also believes that its assessment of income taxes (and other elements of OPG's proposed revenue requirement) would be improved if OPG were to file a complete set of audited financial statements, including a balance sheet, for the prescribed facilities. The Board regulates the rates of a few utilities that are owned by entities that also own substantial unregulated businesses. Those regulated utilities do file separate audited financial statements as part of their applications. The Board directs OPG to file such audited financial statements for the prescribed facilities. Assuming that OPG's next application is filed in mid-2009, the Board expects OPG to file financial statements as at and for the year ended December 31, 2008.

9.2 Nuclear Payment Structure

9.2.1 OPG's fixed payment of $1.2 billion

OPG requested a change in the structure of payments for the nuclear facilities. The current nuclear payment amount is $49.50 per MWh, with OPG being fully at risk for outages at Pickering and Darlington. OPG proposed that the Board approve a fixed payment of $1,221.6 million (25% of OPG's proposed revenue requirement, net of variance and deferral account amortization), payable in equal monthly instalments. The balance of OPG's proposed nuclear revenue requirement would be recovered through a variable payment amount of $41.50 per MWh and a further $1.45 per MWh to cover clearance of variance and deferral accounts.

OPG argued that it should be awarded a significant fixed payment for the nuclear facilities because over 90 percent of nuclear costs are fixed, and because generators in Ontario and other jurisdictions receive some form of fixed payment. It also noted that the rates for utilities that provide regulated distribution services include a fixed component. OPG acknowledged that receiving a significant fixed payment for nuclear facilities would reduce OPG's risk. It submitted that the variable component of the proposed payment structure would still provide a strong incentive to maximize nuclear unit availability, avoid outages, and bring units back from an outage as quickly as possible.

Intervenors were split on the merits of OPG's proposal. CCC, PWU, SEC supported, or did not object to, a fixed component for nuclear payments. CCC submitted that it is more important to mitigate OPG's risk than to provide a meaningful incentive to avoid unscheduled outages. It recommended that the fixed portion of the nuclear payments be set at 50% of the revenue requirement. PWU and SEC supported OPG's proposed 25% fixed payment.

AMPCO, CME, Energy Probe, and GEC-Pembina-OSEA opposed OPG's proposal. AMPCO submitted that it would be inappropriate to relieve OPG of the incentive to maximize nuclear production that is inherent in the fully variable payment structure approved by the government in 2005. CME supported AMPCO's position and argued that if the Board were to approve any amount of a fixed payment for nuclear it should reduce the equity element of the deemed capital structure. GEC-Pembina-OSEA noted that several witnesses were asked to provide examples of generators receiving payments for non-production and that no precedents were provided.

Board Findings

The Board does not approve OPG's fixed payment proposal. The Board will continue the current 100% variable payment structure for nuclear output.

OPG's request to move away from a fully variable payment structure for the prescribed nuclear facilities does not appear to have been in response to a change in operational risk at the plants compared to the risk level in 2005. The Board could not identify any change in the operating environment that would dictate a need to revise the payment structure.

OPG's proposal would result in an increasing effective price per MWh for energy produced from the nuclear plants when OPG's production deteriorates. If OPG's nuclear production for the 21-month period ending December 31, 2009 were to exactly equal its forecast of 88.2 TWh, the proposed payment structure would result in revenue of $4,886.5 million, or $55.40 per MWh (excluding recovery of deferral and variance accounts). If, however, nuclear production is 5% less than forecast, the realized price under OPG's proposal would increase to $56.13 per MWh. The Board is not aware of any generator in Ontario that has such an arrangement, and OPG was not able to provide any relevant examples.

OPG stated that generators in Ontario and other jurisdictions receive some form of fixed payment. It did not provide examples. The Board is aware that generators in some jurisdictions receive fixed capacity payments as compensation for standing ready to generate when called on. As the Board understands those contracts, the fixed compensation paid to the generator is contingent on the generator actually being able to produce when called on. If the generator cannot produce when required, some of the fixed payments are clawed back. This is different from OPG's proposal, which would allow OPG to keep all of the fixed payment regardless of the level of its nuclear output.

The Board is also aware that some contracts between generators and the Ontario Power Authority provide for fixed monthly payments. As far as the Board is aware, generators with those contracts are deemed by the OPA to have operated, and deemed to have earned revenue that reduces the monthly fixed payment, when certain prices prevail in the gas and electricity markets. The fixed monthly payment is reduced by the deemed revenue whether or not the generator was able to generate when the OPA deems that it did so and earn revenue in the IESO market. In the Board's view, the payment structure in these contracts is not equivalent to OPG's proposed structure because the generator will lose part of its fixed payment if it is unable to operate when the OPA deems it to do so.

OPG likens its proposed fixed payment to monthly fixed payments charged to customers by regulated gas and electricity distribution companies. The Board does not accept OPG's comparison. It is true that most of the costs of regulated delivery utilities in Ontario and elsewhere are fixed. But, unlike OPG, those entities are essentially monopoly providers, with an obligation to serve, that must make sure their systems are available and capable of serving customers regardless of the level of customer demand any point. OPG is not seeking to mitigate the risk of fluctuating customer demand. Rather, it is seeking a fixed payment structure to mitigate the risk that OPG is unable to produce the amount of energy that it has forecast.

The Board believes OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast. This is the same position OPG would be in if the nuclear facilities were not regulated and were compensated through the hourly spot market or bilateral contracts.

9.2.2 Separate payment rider for deferral and variance account clearance

OPG said it favours recovering deferral and variance account balances through separate payment riders. It did not propose a separate rider for the hydroelectric accounts, because the amounts being cleared are small, but it did propose a rate rider of $1.45 per MWh to cover clearance of nuclear deferral and variance account balances.

No intervenor opposed establishing a separate rider for clearance of the nuclear accounts.

Board Findings
The Board approves the use of a rate rider to collect the amount of nuclear deferral and variance account balances approved for clearance in Chapter 7 of this decision.

9.3 Hydroelectric Payment Structure

The Board approves continuation of the current 100% variable payment structure for hydroelectric output. It also agrees with OPG that there should be no separate rate rider for recovery of hydroelectric deferral and variance accounts.

Chapter 3 sets out the Board's findings on the hydroelectric incentive payments.

10 IMPLEMENTATION

OPG proposed that its new payment amounts be made effective April 1, 2008 and that the retrospective amounts to April 1, 2008 should be recovered over the balance of the test period outstanding at the time of the issuance of the Board's Decision, through the monthly payments OPG receives from the IESO. The amount to be recovered for the retrospective period would be equal to the difference between the new payments approved by the Board, multiplied by actual production from the regulated facilities during that period, and the actual revenues received by OPG under the existing payment amounts, excluding any hydroelectric incentive revenues.

AMPCO supported OPG's proposal to recover the retrospective amounts back to April 1, 2008 using actual consumption. SEC proposed that the new payment amounts be effective April 1, 2008 except for that portion related to OPG's increased return on equity. No other intervenors made submissions on OPG's implementation proposal. OPG urged the Board to accept OPG's proposal for implementing the new payment amounts, and to reject SEC's proposal.

The Board has determined that the new payment amounts will be effective April 1, 2008 and that the shortfall for the period from April 1, 2008 to the implementation of the Board's order should be recovered over the balance of the test period.

The Board directs OPG to file with the Board, and copy all intervenors, a draft order which will include the final revenue requirement and payment amounts for the prescribed nuclear and hydroelectric faculties, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the amounts used.

With respect to the calculation of the payment amounts, OPG should assume that the IESO can start billing the new rates as of December 1, 2008 and that the payment amounts will be adjusted through the use of a rider to allow for the recovery of the 21 month revenue requirement over the 13 month period remaining in the test period.

With regard to the calculation of production for April 1, 2008 to November 30, 2008, OPG should use the monthly forecasts for both hydroelectric and nuclear production which underpinned its application. This will ensure that OPG remains at risk for its production forecast in the same way it would have been had the payment amounts been set on a prospective basis.

OPG is directed to file the draft order within 10 calendar days of the issuance of this decision. Intervenors shall have 7 calendar days to respond to the Company's draft order. The Company shall respond within 5 calendar days to any comments by intervenors.

DATED at Toronto, November 3, 2008

ONTARIO ENERGY BOARD

Original Signed By

____
Gordon Kaiser
Presiding Member & Vice Chair

Original Signed By

____
Cynthia Chaplin
Member

Original Signed By

____
Bill Rupert
Member

APPENDICES

TO

DECISION WITH REASONS

EB-2007-0905
ONTARIO POWER GENERATION INC.

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

Ontario Power Generation Inc. (OPG) filed its application for new payment amounts on November 30, 2007. On December 13, 2007 the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The Board issued Procedural Order No.1 on January 23, 2008 which established the procedural schedule for all events, including the hearing of OPG's request for an interim payment amount adjustment to take effect on April 1, 2008. Procedural Order No.1 also provided a draft issues list and a listing of the parties to the proceeding.

The procedural schedule included the following:

- Submissions on the issues list and the interim payment request were filed by February 1, 2008.
- The Issues Day/Interim payment hearing was held on February 6-7 2008.
- Interrogatories to OPG were filed by March 24, 2008. OPG responded to interrogatories by April 11, 2008.
- Intervenors and Board staff filed evidence by April 18, 2008.
- Interrogatories on intervenor and Board staff evidence were filed by April 23, 2008.
- Intervenors and Board staff filed responses to interrogatories by May 8, 2008.
- A technical conference was held on May 13 and 14, 2008.
- The oral Hearing commenced May 22, 2008

On February 7, 2008, the Board orally ruled on the matter of the issues list and OPG's request for an interim payment adjustment after hearing submissions from the parties, including OPG, the Association of Major Power Consumers of Ontario, the Schools

Energy Coalition, and Energy Probe, Power Workers Union and the Independent Electricity System Operator.

On March 20, 2008, April 9, 2008 and April 18, 2008 the Board issued Procedural Orders No. 2, No. 3 and No. 4 respectively which amended or extended the events schedule of the proceeding.

In response to OPG's request that certain interrogatory responses be treated confidentially, the Board issued Procedural Order No. 5 pursuant to the Board's Rules of Practice and Procedure and Practice Direction on Confidential Filings.

On July 29, 2008 the Board issued Procedural Order No. 6 which set out the timetable for the filing of cost claims by eligible intervenors in accordance with the Board's Practice Direction on Cost Awards.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that 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 Richard Battista Russell Chute Chris Cincar Russell Holden
Ontario Power Generation	Michael A. Penny Josephina Erzetic Andrew Barrett Barbara Reuber
Association of Major Power Consumers in Ontario	Mark Rodger Adam White Wayne Clark Tom Adams Lawrence Murphy
Canadian Manufacturers & Exporters	Peter Thompson

Consumers Council of Canada	Robert Warren Julie Girvan
Energy Probe Research Foundation	Peter Faye David MacIntosh Lawrence Schwartz Norman Rubin Kimble Ainslie
Green Energy Coalition	David Poch
Pollution Probe Foundation	Murray Klippenstein Basil Alexander Jack Gibbons
Power Workers Union	Richard Stephenson John Sprackett Judy Kwik Alfredo Bertolotti
School Energy Coalition	Jay Shepherd Bob Williams Mikaela Cameron Rachel Chen
Vulnerable Energy Consumers Coalition	Michael Buonaguro Bill Harper

WITNESSES

The following OPG employees appeared as witnesses.

David Halperin	Director, Business and Financial Planning, Corporate Finance
Fred Long	Vice President, Financial Planning
Colleen Sidford	Vice President, Treasurer
Joan Frain	Manager, Water Policy and Planning Water Resource Division
Don B. Gagnon	System Support Manager Niagara Plant Group

Mario Mazza	Director, Business Support and Regulatory Affairs Hydro Business Unit
Mark Shea	Asset and Technical Services Manager Ottawa/St Lawrence Plant Group
Ken Lacivita	Director, Trading and Origination Energy Markets
Robert Boguski	Senior Vice President, Business Services and Information Technology
John Mauti	Director, Nuclear Reporting
Paul Pasquet	Deputy Site President, Pickering B
Bill Robinson	Senior Vice President, Nuclear Programs and Training
Dana Letts	Outage Program Manager Nuclear Programs and Training
Vincent Gonsalves	Director, Business Planning
Michael Allen	Director, Work Management
Michael McFarlane	Outage Manager Darlington
Robert Latimer	Department Manager, Strategic Planning, Pickering A
Mark Arnone	Director, Projects and Modifications
Randy Leavitt	Director, Investment Management
Craig Sellers	Chief Engineer, Nuclear New Build
Laurie Swami	Director of Licensing, New Generation Development
Mario Cornacchia	Director, Commercial Services Inspection and Maintenance and Commercial Services
Dennis Dodo	Controller, Inspection and Maintenance Services
Bob Morrison	Vice President, Engineering and Modifications and Chief Nuclear Engineer
Neil Brydon	Manager, External Reporting and Policy

Angelo Castellan	Director, Nuclear Waste Business Support
Robin Heard	Vice President, Financial Services
Lorraine Irvine	Vice President, Compensation and Benefits
Tom Staines	Controller, Corporate Accounting Finance
Andrew Barrett	Vice President, Regulatory Affairs and Corporate Strategy
Lubna Ladak	Manager, Regulatory Finance
Sean Granville	Director, Nuclear Programs

OPG also called the following expert witness: Kathleen McShane of Foster Associates Inc.

The intervenors and Board staff called the following expert witnesses:

- Laurence Booth of the University of Toronto appearing for VECC and CCC
- Paul Chernick of Resource Insight Inc. appearing for GEC
- A.J. Goulding of London Economics International appearing for Board staff
- Lawrence Kryzanowski of Concordia University and Gordon Roberts of York University appearing for Pollution Probe
- Lawrence Murphy of Henley International Inc. and Tom Adams appearing for AMPCO
- Lawrence Schwartz of York University appearing for Energy Probe

APPROVALS SOUGHT BY OPG IN EB-2007-0905

(Source; Exhibit A1- 2- 2)

- An order from the OEB declaring OPG's payment amounts interim as of April 1, 2008.

- An order from the OEB establishing interim payment amounts of $35.35/MWh for the
  - output of Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station,
  - DeCew Falls I, DeCew Falls II, and R.H. Saunders Generating Stations (the "regulated
  - hydroelectric facilities") and $53.00/MWh for the output of Pickering A Generating Station, Pickering B Generating Station, and Darlington Generating Station (the "nuclear
  - facilities") effective April 1, 2008. During the period of interim rates, OPG expects to
  - retain the hydroelectric incentive mechanism under O. Reg. 53/05 under which the
  - output from the regulated hydroelectric facilities in excess of 1900 MWh in any hour receives market price.

- The approval of a revenue requirement of $1283M for the regulated hydroelectric facilities and a revenue requirement of $5152M for the nuclear facilities for the period of April 1, 2008 through December 31, 2009 (the "test period") as set out in Ex. K1-T1-S1.

- The approval of a rate base forecast of $3886M and $3870M for the regulated hydroelectric facilities for the years 2008 and 2009, respectively and $3515M and $3484M for the nuclear facilities for the years 2008 and 2009, respectively, as summarized in Ex. B1-T1-S1. OPG's request for this approval is supported by an examination of the asset and liabilities values and other related matters in the 2006 audited financial statements pursuant to paragraph 6 (2) 5 of the Regulation and asset forecast as found in Exhibit B.

- Approval of a capital budget for the regulated hydroelectric facilities for the test period, as presented in Ex. D1-T1-S1 and for the nuclear facilities for the test period, as presented in Ex. D2-T1-S1.
- Approval of a production forecast of 31.5 TWh for the test period for the regulated hydroelectric facilities and 88.2 TWh for the test period for the nuclear facilities. Production forecast is presented in Ex. E.

- Approval of a deemed capital structure of 42.5 percent debt and 57.5 percent equity and a combined rate of return on rate base of 8.48 percent and 8.56 percent for 2008 and 2009, respectively, including a rate of return on equity ("ROE") forecast of 10.5 percent, as presented in Ex. C1-T1-S1 and Ex. C1-T2-S1.

- Approval of the automatic adjustment mechanism to adjust the rate of return on common equity in future periods, as discussed in Exhibit C1-T1-S1.

- Approval of a payment amount for the regulated hydroelectric facilities of $37.90/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO") – administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO - administered market. The payment amount for the regulated hydroelectric facilities is set out in Ex. K1-T2-S1 and the design of the regulated hydroelectric payment amount is set out in Ex. I1-T1-S1.

- Approval of a payment amount for the nuclear facilities, of $58.2M/month plus $41.50/MWh, as set out in Ex. K1-T3-S1.

- For the nuclear facilities, approval for recovery of $342M from the variance and deferral accounts using a payment rider of $1.45/MWh, as presented in Ex. J1-T1-S1 and Ex. J1-T2-S1. For the regulated hydroelectric variance account, recovery of $0.7M by adding this amount to the revenue requirement used to calculate the hydroelectric payment amount, as presented in Ex. J1-T2-S1 and Ex. K1-T1-S1.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:

  - A variance account to record the deviation from forecast revenues associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions.

  - A variance account to record the deviation from forecast revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.

  - A variance account to record the deviation from forecast non-capital costs associated with work to increase capacity or to refurbish a generation facility. The account would include deviations in costs associated with the potential refurbishment of Pickering B and Darlington Generating Stations.

  - A variance account to recover the deviation from forecast non-capital costs for planning and preparation for the development of proposed new nuclear generation facilities.

  - A variance account to record the deviation between actual and forecast nuclear fuel costs.

  - A variance account to record the customer's share of revenues from energy sales to Hydro Quebec as a result of segregated mode of operation at R.H. Saunders, and from water transactions at the regulated hydroelectric facilities.

  - A variance account to record the deviation between actual and forecast pension and other post-employment benefit expenses related to changes in the discount rate.

  - A deferral account to record non-capital costs associated with the planned return to service of units at the Pickering A Generating Station.

- A deferral account to record the revenue requirement impact of the change in the nuclear decommissioning liability arising from the December 2006 approved reference plan as defined in the Ontario Nuclear Funds Agreement.

- A variance account to capture the tax impact of changes in tax rates, rules and assessments.

DECISION ON INTERIM PAYMENTS - EB- 2007- 0905

Source: EB-2007-0905 Transcript dated February 7, 2008 p.p. 111-118

See following pages:

here, of course, is that we have two, at least two, of the significant intervenors who represent consumers - that is, CCC and VECC - acknowledging, in this case, that it does make sense to think about some rate smoothing.

MS. CHAPLIN: But I guess in this case we have residential consumer groups perhaps agreeing with that --

MR. PENNY: Yes.

MS. CHAPLIN: -- but industrial consumer groups retaining that position that it is better to under-collect than to over-collect?

MR. PENNY: Absolutely. No doubt about it.

MS. CHAPLIN: Okay, thank you.

MR. KAISER: Thank you. We will come back at 2:15.

--- Luncheon recess taken at 12:58 p.m.

--- On resuming at 2:45 p.m.

MR. KAISER: Please be seated.

DECISION:

MR. KAISER: The Board heard submissions this morning from a number of interested parties with respect to an application by Ontario Power Generation for interim rates. This relates to the application OPG filed on November 30th under section 78.1 of the Ontario Energy Board Act for approval of increases in payment amounts for the output of certain next generation facilities effective April 1st, 2008.

In particular, OPG seeks two Interim Orders. The first Order would make its current payment amounts interim, effective April 1st, 2008. Secondly, they seek an Interim

Order increasing OPG's payment amounts on an interim basis to $35.35 per megawatt hour for hydro-electric production, and $53 per megawatt hour for nuclear production.

There are two questions before us. The first is, does the Board have jurisdiction in this case to issue these types of orders? And the second is, if we do have the jurisdiction, should we exercise that jurisdiction, and to what extent?

Dealing with the first question, first. Mr. Penny, on behalf of OPG, has referred the Board to a number of cases with respect to the issuance of interim orders throughout the country. It is useful in the context of this case to identify the essential characteristics of an Interim Order. This is at paragraph 28 of his factum.

First, an Interim Order does not require any decision on the merits of an issue. That will be settled in the final decision. The purpose of an Interim Order is to provide relief for any deleterious affects caused by the length of the proceedings. Secondly an Interim Order is temporary. It can be changed retrospectively once the final determination is made. Thirdly, an Interim Order assumes and requires that a final order will be made. One initiates the process and the other ends it, a point that Mr. Penny made on a number of occasions.

Mr. Penny has also referred us to the Supreme Court of Canada decision in the Bell Canada case where the Court stated:

"Traditionally, such interim rate orders dealing in interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceeding.

"Such decisions are made in an expeditious manner on the basis of evidence that would often be insufficient for the purposes of a final decision. The fact that an order does not make any decision on the merits of an issue to be settled in the final decision and the fact that its purpose is to provide temporary relief against deleterious effects caused by the duration of the proceedings are essential characteristics of an interim order."

There is no question that section 21(7) of the OEB Act grants the Board clear authority to issue interim orders. It has done so on a number of occasions. Mr. Penny referred to a number of those decisions including decisions involving IESO, the OPA, and various gas companies.

Of particular interest here is whether a reading of section 78.1 of the Act leads to a conclusion that the Board cannot or should not issue an interim order in this case.

Section 78.1(2)(b) provides, in relevant part, that the payment amount shall be the amount determined:

"in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the latter of

(i) the date prescribed for the purpose of this subsection; and

(ii) the effective date of the Board's first Order under this section in respect to the generator.

O. Reg 53/05 specifies the amount, for the purposes of section 78.1(2) that the IESO is required to pay OPG for the output from the prescribed facilities from April 1st, 2005 to the later of:

(i) March 31st, 2008; and

(ii) the day before the effective date of the Board's first Order in respect of Ontario Power Generation Inc.

Now, much was made of the fact as to whether a first order in this section meant an Interim Order or whether it meant a Final Order.

It was Mr. Penny's position that it meant a Final Order.

Mr. Faye, in his submissions on behalf of Energy Probe, argued that if we were to look, for instance, at Regulation 62.5, that this Regulation required the Board to accept certain amounts and take certain steps in a very distinct fashion. He argues that if a first order was an Interim Order (which chronologically it might seem to be), some real complications would result and leads to the conclusion that an interim order should not be granted.

Having listened to the submissions of all of the parties, the Board is of the view that there is nothing in the language of section 78.1 or section 4 of Ontario Regulation 53/05 that removes the power of the OEB to set interim payment amounts, nor can that restriction be implied as necessary to the operation of the legislative scheme. In fact, the language of these provisions recognizes that when an OEB order concerning payment amounts is made, may well be different from the effective date of that order. This supports the interpretation that the OEB's power to make interim orders applies to payment amounts under section 78.1.

An Interim Order is not necessarily a first order within the meaning of the Act. A reasonable interpretation of the words "first order" is that it is a Final Order which determines what might be described as the first rates set definitively by the Board and not prescribed by Regulation. An Interim Order can by its nature be time limited and subject to whatever is determined in the Final Order. Section 78.1 does no more than establish that the payment amounts are as prescribed by regulation until the latter of March 31st, 2008 and the effective date of the OEB's first order. The language of section 78.1 does not suggest that the OEB's power under section 21.7 to issue interim orders is in any way limited or abrogated other than by the limitation that any such order could not purport to have an effective date before April 1st, 2008.

The object of the Act and the intention of the legislature is clear. In our view, the clear purpose of section 78.1 of the Act and section 4 of the Regulations is to fix the OPG payments for three years until March 31st, 2008 and to leave to the OEB thereafter the task of determining payment amounts that are just and reasonable in accordance with the regulations.

In summary, the ability to fix just and reasonable payment amounts would be compromised, in our view, if the Board can only take action after a full and final hearing. The power to make interim orders is clearly confirmed by the Act and is necessary for the protection of both customers and generators. This power can be abrogated only by the clearest statutory language. There is nothing in section 78.1 that supports that conclusion.

This, then, leads us to the second aspect of this motion. This is the Applicant's request, in the first instance, that the existing or current payment amounts be declared interim effective April 1st, 2008. And in the second case that a Interim Order be issued, increasing those payment amounts, on an interim basis, to the amounts I described earlier, namely $35.35 per megawatt hour for hydroelectric production and $53 per megawatt-hour for nuclear production.

We will consider the first aspect first; whether the existing payment amounts should be declared interim effective April 1st, 2008. The Board agrees that that should be the case and an Order will issue to that effect.

We see no harm resulting to any party as a result of such an Order. It is not unusual for such Orders to issue.

It preserves the ability of the Board to set rates effective April 1st, 2008. And the ability of the utility to recover any ultimately determined revenue deficiency from that date.

That leads us to the second question; whether the payment amount should be increased to the requested amount on an interim basis effective the same date, April 1st, 2008.

This application is denied. The requested amount, which I have described earlier, is said by the Applicant to be 50 percent of the amount claimed in its Application. This calculation is set out at paragraph 108 of the Applicant's Factum. It refers in part to the cost of capital. Instead of claiming the whole amount they would receive if they receive an ROE of 10.5 percent, they have reduced that to Hydro One's 8.34 percent ROE. They also added two recovery amounts, 85.3 million for the nuclear liability deferral account, and another 67.7 million for recovery of specified deferral and variance accounts balance. The latter two accounts are accounts where recovery is required by the Regulation.

OPG has claimed a total revenue deficiency of some $760 million accumulating, they say, at the rate of about $39 million a month.

The Board is concerned, at this point, with granting the requested payment increase. The main argument was not financial harm, which we often hear in these cases and is often the basis for interim rate increases. Rather, OPG seeks rate smoothing to avoid rate shock to consumers.

Of course, any concern with rate shock assumes that there will be some rate increase; otherwise, smoothing is not necessary. Mr. Stephenson, on behalf of his client, the Power Workers' Union, supported the applicant and said, "we know some increase is coming, and we might as well start to absorb some of it sooner rather than later".

I should add that the applicant was supported by three consumer groups in this regard, the Consumers Council of Canada, VECC and Power Workers' Union, but was opposed by three other consumer groups, the School Energy Coalition, AMPCO and Energy Probe. So the consumer groups were divided on the issue.

In the end, the Board believes that if smoothing is the objective and if smoothing is required, at it can be achieved prospectively. It is not necessary to do that by early rate implementation.

We also note the concerns of AMPCO, that some of the increase sought relates to increased cost of capital, particularly return on equity. They expect this will be a contentious issue. AMPCO was concerned that the Board not be seen to prejudge that issue at that point.

That completes the Board's ruling in this matter. Any questions?

MR. PENNY: No, thank you.

MR. KAISER: Thank you. Thank you, gentlemen, ladies.

--- Whereupon the hearing adjourned at 3:02 p.m.

Excerpt: Section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O.1998, c.15 (Schedule B).

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

   (i) March 31, 2008, and

   (ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.

2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.

2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

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Memorandum of Agreement

Source: EB-2007-0905 Exhibit A1-4-1 Appendix B

Filed: 2007-11-30
EB-2007-0905
Exhibit A1-4-1
Appendix B

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

    - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
    - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
    - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
    - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of

Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. <u>Financial Framework</u>

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. <u>Communication and Reporting</u>

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. <u>Review of this Agreement</u>

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

Opinion

on

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

November 2007

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I. INTRODUCTION AND EXECUTIVE SUMMARY

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies, in more than 150 proceedings in Canada and the U.S. My professional experience is provided in Appendix J.

I have been requested by Ontario Power Generation Inc. ("OPG") to recommend a capital structure and fair return on equity for the Company's prescribed assets. OPG's prescribed assets include six hydroelectric generating stations comprising 3332 MW of capacity and three nuclear generation stations comprising 6606 MW of capacity.[1]

[1] Regulated operations also include the costs and revenues from the lease arrangements between OPG and Bruce Power for the Bruce Nuclear Generating Stations.

B. CONCLUSIONS

1. The return and capital structure for OPG's regulated operations are governed by the fair return standard.

2. A fair return for OPG's regulated operations, which encompasses both capital structure and return on equity, should respect the stand-alone principle.

3. OPG is entitled to the opportunity to earn a fair return on the assets that are devoted to, and are used and useful in, the provision of regulated service, i.e., its rate base. An original cost rate base should be used for purposes of determining the capital structure and the application of the return on equity.

4. A deemed capital structure should be adopted for OPG because:
   a. It is compatible with the premise that the allowed return should be based on the stand-alone risk of the regulated operations,
   b. It provides a means to implement the basic principle of finance that the higher the business risk, the lower should be the debt ratio, and
   c. OPG has significant non-regulated operations whose business risks and cost of capital may be different from the risks and cost of capital of its regulated business.

5. To estimate a reasonable return on equity and capital structure for OPG, I estimated the return on equity that would be applicable to a benchmark (average risk) Canadian utility. I subsequently estimated the deemed capital structure for OPG that:
   a. Is compatible with its business risks;
   b. Would permit it to achieve a stand-alone debt rating similar to that of the proxy utilities used to establish the benchmark return; and,

c. Would equate the level of total (business and financial) risk faced by OPG to that of a benchmark (average risk) Canadian utility.

6. The benchmark return on equity was estimated at 10.25-10.75%. The fair return for a benchmark utility reflects the following:

a. The return on equity is based on the results of three tests, equity risk premium, discounted cash flow and comparable earnings.

b. The equity risk premium test results are based on three separate approaches. The equity risk premium test supports the following return:

Risk-Free Rate	5.0%
Equity Risk Premium	4.25-5.25%
Financing Flexibility Adjustment	0.5%
Return on Equity	9.75-10.75%

c. The discounted cash flow test, applied to a sample of benchmark low risk U.S. utilities supports a cost of equity of 9.25-9.5%. With a 0.50% adjustment to the "bare-bones" market cost of equity for financing flexibility, a fair return based on the DCF test is 9.75-10.0%.

d. The comparable earnings test shows that, based on the achievable earnings returns of low risk competitive non-regulated Canadian firms, a fair return applicable to a benchmark utility would be approximately 12.5%.

e. With primary weight given to the two capital market tests, equity risk premium and discounted cash flow, the fair return for a benchmark Canadian utility is 10.25-10.75% (mid-point of 10.5%).

7. A return of 10.5% is applicable to OPG's regulated operations at a deemed common equity ratio sufficient to equate their total risk (business and financial) to that of the proxies used to estimate the benchmark return.

8. The deemed capital structure for OPG should respect the following principles:
   a. The stand-alone principle.
   b. Compatibility of the capital structure with OPG's business risks.
   c. Maintenance of creditworthiness/financial integrity.
   d. Compatibility with the benchmark return on equity.

9. With respect to relative business risk, OPG's regulated operations face significantly higher business risks than a benchmark average risk Canadian utility, or a low risk U.S. utility.

10. To ensure access to the public debt markets, the capital structure for OPG's regulated operations should be sufficient to achieve debt ratings on a stand-alone basis in the A category. The reasons for targeting an A rating include:
    a. OPG is facing the potential of significant capital expenditures, for which it may require public debt market access on reasonable terms and conditions. An A rating will help ensure access on reasonable terms and conditions when the debt capital is required.
    b. The market for BBB rated debt in Canada remains relatively small, and is particularly limited for long-term (i.e., 30 year) issues. OPG should have the ability to access the long-term debt market to finance long-term assets.
    c. The benchmark equity return recommended for OPG is intended to represent the return applicable to an average risk, A rated, Canadian utility. Targeting an A rating through the deemed capital structure ensures compatibility of the ROE and capital structure.

11. The current DBRS and S&P debt ratings for OPG's consolidated operations are based on equity ratios in the range of 55-60%. Based on an analysis of the debt rating reports, including the rating agencies' assessment of the business risks of the regulated

operations, the deemed common equity ratio for OPG's regulated operations would need to be in a similar range to maintain similar stand-alone debt ratings.

12. The quantitative guidelines of the debt rating agencies for a utility facing a similar business risk profile to OPG's regulated operations and an A debt rating support a deemed common equity ratio in the range of 55-60%.

13. The average common equity ratio for the electric utility industry in North America is approximately 45%, which, in conjunction with returns on equity in the 11-12% range, is associated with a debt rating of BBB. The deemed common equity ratio for OPG at the benchmark return on equity of 10.5% is premised on achieving an A rating. The deemed equity ratio will need to be materially higher than the industry average of 45% to notionally achieve an A debt rating.

14. OPG's regulated generation operations face higher business risk than the benchmark utilities, which are largely "wires" or "pipes" companies. To estimate the common equity ratio for OPG's regulated operations that would permit the application of the benchmark return of 10.5%, I estimated the incremental cost of equity for OPG from the cost of equity for utilities with a high proportion of generation assets. From their cost of equity, I also derived a generation-only cost of equity. The incremental costs of equity for the "high generation" utilities and for generation-only were then translated into the common equity ratio required to equate OPG's total risk to that of a low risk benchmark utility based on capital structure theory. The analysis, which takes account of the application of two capital structure theories, indicates that the range of the required common equity ratio for OPG's regulated operations consistent with the benchmark return is 55-60%.

15. A review of capital market participants' views indicates that the returns available to comparable U.S. utilities are materially higher than the returns that are allowed to Canadian utilities, the returns allowed for Canadian utilities are generally regarded as too low, and the returns that investors expect and are achieving from the traded utility entities in Canada are considerably higher than the returns that have been allowed by regulators. These factors are legitimate considerations to be taken into account in setting a fair and reasonable return for OPG's regulated operations, and are supportive of the recommended capital structure and return on equity.

16. I recommend the adoption of an automatic adjustment formula for return on equity for OPG. Since OPG is facing multiple limited issue proceedings, with ROE assigned to the first, the implementation of an automatic adjustment mechanism to operate until full rebasing of regulated payments is complete is particularly warranted.

The Board's existing formula, that is, a 75 basis point change in ROE for every one percentage point change in forecast 30-year Canada bond yields is a reasonable reflection of the relationship between the cost of equity and interest rates. However, the key to the success of the formula is the initial adoption of a reasonable return on equity.

The automatic adjustment mechanism needs to preserve OPG's right to seek a review of the formula if OPG's ability to attract capital on reasonable terms is at risk. In the alternative, OPG should be able to seek a review of its deemed capital structure, should its business risks change materially or its access to capital is threatened.

The formula should also be reviewed if forecast long Canada bond yields fall below 3.0% or exceed 8.0%, as those extremes could signal a material change in the capital market environment.

II. PRINCIPLES OF ANALYSIS FOR CAPITAL STRUCTURE AND RETURN ON EQUITY

A. THE FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[2] which are echoed in numerous regulatory decisions across North America.[3] A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

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[2] The principal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

[3] In EB-2005-0421(Toronto Hydro), dated April 12, 2006, the OEB stated, “And, as a matter of law, utilities are entitled to earn a rate of return that not only enables them to attract capital on reasonable terms but is comparable to the return granted other utilities with a similar risk profile.” (pages 32-33)

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, may potentially degrade the quality of service or deprive existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers. The OEB has recognized the importance of a financially viable energy sector and the need for additional energy infrastructure, particularly generation and transmission, in its Strategic Business Objectives set out in its 2006-2009 Business Plan (December 2005). Fair and reasonable returns are central to the achievement of those objectives.

B. THE STAND-ALONE PRINCIPLE

A fair return for OPG's regulated operations, which encompasses both capital structure and return on equity, should respect the stand-alone principle. The stand-alone principle has been respected by virtually every Canadian regulator, including the OEB, in setting both regulated capital structures and allowed returns on equity.

The stand-alone principle is the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the regulated operations if they were raising capital in the public markets on the strength of their own business and financial parameters. In other words, application of the stand-alone principle to OPG's regulated operations means they should be treated for regulatory purposes as if they were operating separately from the other activities of the firm. The cost of capital borne by ratepayers should reflect neither subsidies given to, nor taken from, other activities of the firm.

The evaluation of the appropriate capital structure and common equity return on a "stand-alone" basis avoids: (1) the misconception that the cost of raising capital to invest in a project (the financing decision) is the same as the cost of capital (required return) of the project (the investment decision); and (2) the potential that hidden subsidies created by using an inappropriate cost of capital can distort the economics of the project itself. To illustrate, the Federal Government can raise long-term debt at relatively low interest rates because its taxing power assures the cash flows needed to reimburse investors. If the Federal Government were to consider investing either in natural gas exploration and development or a water utility, its evaluation of the two potential investments should be based on required returns that reflect the different business risks of the two projects, not the cost to the Federal Government of raising debt to finance its investment. A failure to do so, that is a failure to respect the "stand-alone" principle, could lead to the erroneous conclusion that the oil and gas development project was the superior project and thus to an uneconomic allocation of capital resources. Effectively, the Federal Government would be subsidizing natural gas exploration and development, while potentially allowing a superior project to fail to attract investment funds. Respect for the stand-alone principle ensures that scarce capital resources are efficiently allocated to their best use. The allowed return should thus represent the stand-alone risk and associated cost of capital of the operations, not the happenstance of ownership.

C. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND COST OF CAPITAL

The stand-alone principle is grounded in the basic tenet of financial theory that the opportunity cost of capital to a firm, or division of a firm, is a function of its business risk. Business risk comprises the operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk is a function of the fundamental characteristics of the operations, i.e., of the firm's assets. In the absence of income taxes and the added costs related to the loss of financial flexibility and financial distress or ultimately bankruptcy, the overall cost of capital would not change as the manner in which it was financed changed. The cost of capital would be the same if a firm were financed with 100% equity or 100% debt. In the absence of income taxes, the sum of the cash flows, available to both the debt holders and equity holders does not change as the capital structure changes. However, the use of debt creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises, but the overall cost of capital is constant.

However, two factors alter the conclusion that the cost of capital stays constant as the capital structure changes. First, the facts that (1) debt is less expensive than equity because debt investors take precedence over equity investors, and (2) interest expense on debt is deductible for corporate income tax purposes means that there is a cost advantage to using debt. Thus, financing with a combination of debt and equity can lower the overall (weighted average) cost of capital. Second, and partly offsetting the cost advantage of adding debt, are the additional costs that are incurred as more debt is added to the capital structure. As the debt in the capital structure increases, additional costs are incurred in the form of loss of financial flexibility and financial distress, e.g., more stringent debt covenants, restrictions on the amount and term of debt the market is willing to accept, and a decreased ability to access the market at the time funds are required. These additional costs negatively impact not only explicit costs of debt and equity financing, but can ultimately impact the ability to operate the business efficiently. As a result, too much debt will increase the weighted average cost of capital, as the costs of financial distress will outweigh the benefits of additional debt.

Two other factors can offset some of the advantage of using debt in the capital structure. The first factor is the impact of personal income taxes on interest income. While interest expense is deductible at the corporate level, the corresponding interest income is taxable to individual investors at higher rates than equity income. Second, in the case of utilities, the benefits of the tax deductibility of interest expense flow to ratepayers, not shareholders, as the utility revenue requirement is reduced to reflect the lower income tax expense. (In contrast, for unregulated companies, the benefits of interest expense deductibility will flow to equity shareholders in the form of a higher return.)

In theory, when all these factors are taken into account, there should be an optimal capital structure, i.e., one that minimizes the overall cost of capital. In practice, the interactions of the various factors make the optimal capital structure impossible to pin-point, and there exists a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably. A key message is that the capital structure and the required return on equity are inter-dependent: As the debt ratio of the regulated operations rises, the cost of equity also rises. That relationship needs to be reflected in OPG's capital structure and allowed return on equity.

D. RATE BASE AND CAPITALIZATION

Under the fair return standard, a utility is entitled to the opportunity to earn a fair return on the investor-supplied capital that finances the assets that are devoted to, and are used and useful in, the provision of regulated service. The rate base represents the measurement of the assets that are used and useful in the delivery of public utility service; it corresponds to the amount of capital that has been provided by investors and upon which investors are allowed the opportunity to earn a fair return.

The most prevalent construct for measuring rate base in North America is a historic cost model, often referred to as "original cost rate base." Under the original cost methodology, the rate base is measured using the cost of the assets at the time they are first devoted to public service. When an original cost rate base is used, the return on rate base reflects the embedded cost of debt and a nominal (inclusive of inflation) return on equity. The domination of original cost ratemaking reflects the results of more than half a century of regulatory and court decisions.[4] Virtually every regulated utility in Canada relies on an original cost rate base for purposes of determining the allowed return on capital.

While the benefits of alternative models for rate base determination continue to be debated in North America from time to time, there is no evidence that the original cost methodology for rate base valuation would preclude utilities from attracting capital on reasonable terms and conditions or from earning a return that is comparable to that of similar risk enterprises as long as the level of the return itself recognizes the manner in which the rate base is measured. Moreover, the requirement that the OEB accept the financial statement asset and liability values of OPG as per Regulation 53/05 effectively eliminates from consideration any of the methodologies that are not derived from original cost (e.g., reproduction or replacement cost).

E. CAPITAL STRUCTURE: DEEMED VERSUS ACTUAL[5]

As indicated in Chapter II.C, the cost of capital to the utility is a function of business risk. It is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares to finance a portion of its assets. The capital structure, comprised of debt, preferred share and common equity, can be viewed as a summary measure of the financial risk of the firm. While there is no universal agreement whether a single optimal capital structure for a firm exists, there is agreement that, as a general proposition, companies with less business risk can safely assume more debt than those with higher business risk without impairing their ability to access the capital markets on reasonable terms and conditions. In principle, higher business risk can be "offset" by assuming less financial risk. Thus, two utilities with different levels of business risk

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[4] Original cost rate base became the standard after the watershed U.S. Supreme Court decision, *Federal Power Commission v. Hope Natural Gas (320 U.S. 391 (1944))*, which addressed the controversy between original cost and fair value. In its decision, the Court held that it is the end result, not the method employed to value the rate base that is important. As a result of the Court's findings in *Hope*, the original cost rate base became the standard, and the focus of regulation shifted from the valuation of the rate base to the fairness of the rate of return and the end result.
[5] Appendix A contains more detail on the history of, and issues related to, deemed capital structures.

can face similar costs of debt and equity if the utility facing higher business risk maintains a lower debt ratio than the utility facing lower business risk.

The concept of a deemed, or hypothetical, capital structure can be viewed as a means of imputing for regulatory purposes a level of financial risk that is "consistent" or "compatible" with the level of business risk that a utility faces. The term "deemed capital structure" simply refers to the imputation, for ratemaking purposes, of a capital structure that is different from the actual or reported capital structure as derived from the utility's financial statements. A deemed capital structure is typically applied by estimating the rate base, applying a specified percentage of common equity to the rate base, assigning to the rate base actual outstanding and forecast issues of long-term debt and preferred shares, and then, to the extent that the capital structure does not equal the rate base, "deem" the gap to be debt.

I recommend the adoption of a deemed capital structure for OPG's regulated operations.[6] The principal reasons for this recommendation are as follows:

1. Using a deemed capital structure is consistent with basing the allowed return on an opportunity cost of capital that reflects the use of funds (the risks of the operations to which the funds are committed), rather than the source of those funds.

2. Using a deemed capital structure is consistent with regulatory practice (consistent with financial theory) of adherence to the stand-alone principle as followed by Canadian regulators, including the OEB, in setting the allowed return on rate base.

3. Using a deemed capital structure allows the general principle to be applied that the higher is the regulated operations' business risk, the lower the debt ratio should be. Recognizing

[6] Issues relating to the specification of the appropriate deemed capital structure for OPG's regulated operations are addressed in Chapter IV.

the level of the regulated operations' business risks primarily through the allowed capital structure is a reasonable and accepted regulatory approach for differentiating among utilities and compensating them for differences in business risk.

4. OPG has significant non-regulated operations whose business risks and cost of capital may be different from the risks and cost of capital of its regulated business.

5. The use of a deemed capital structure provides assurance that ratepayers are protected from any negative impacts on the consolidated firm's cost of capital of unregulated operations.

III. BENCHMARK RETURN ON EQUITY

A. CONCEPT OF BENCHMARK RETURN ON EQUITY

As indicated in Chapter II, the cost of equity is a function of both business and financial risk. Financial risk, in turn, is a function of capital structure; the lower the common equity ratio, the higher is the financial risk and the higher is the cost of equity. When a utility is regulated on the basis of its actual capital structure or a previously approved deemed capital structure, its financial risk must be addressed through the return on equity. The fair return for a utility with a "fixed" capital structure would then be determined by (1) selecting a sample or samples of proxy companies of relatively similar business risk to the utility; (2) estimating the samples' cost of equity; (3) quantifying any difference in equity return requirement between the utility and the proxies due to differences in their capital structure; and (4) applying the financial-risk adjusted return on equity to the utility. However, for OPG both an appropriate deemed capital structure and fair return need to be determined. In setting the two values simultaneously, two basic principles need to be recognized. First, the higher the business risk that a utility faces, the lower would be an appropriate debt component, that is, one that would ensure the utility's ability to attract capital on reasonable terms and conditions. Second, the higher the debt component that is chosen for a regulated firm facing a given level of business risk, the higher would be the cost of equity and the reasonable allowed return on equity.

It is not possible to identify close proxies with equity market data, particularly within the Canadian capital market context, that can be used to directly estimate either a reasonable capital structure or the cost of equity for OPG's regulated operations, for two reasons. First, OPG's regulated operations are unique. Second, there are a very limited number of publicly-traded regulated companies in Canada. In the absence of Canadian proxies of similar risk to OPG, there are essentially two approaches that can be used. The first approach entails estimating and applying to OPG the equity return that would be applicable to a "benchmark" or average risk Canadian utility. That return will be referred to as a "benchmark return". A deemed capital structure for OPG would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return; and (c) would equate the level of total (business and financial) risk faced by OPG to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the deemed common equity ratio for OPG's regulated operations established so that no adjustment to the benchmark return on equity is required.[7]

The second approach sets the deemed capital structure first, relying on factors such as debt rating agency guidelines for an investment grade debt rating and capital structure ratios maintained by peers in the industry. This approach entails establishing a deemed common equity ratio that is reasonable, but would not necessarily equate OPG's total (business plus financial) risk to that of a benchmark utility. In the implementation of this approach, OPG's total risks would be compared to those of the proxy firms used to establish the benchmark. If OPG's total risk, at the specified deemed common equity ratio is higher than that of the benchmark utility, the incremental equity return requirement needs to be estimated and added to the return on equity applicable to a benchmark utility. The key difference between the first and second approaches is that in the second, both capital structure and return on equity are essentially "moving parts." Because there are so few publicly-traded utilities in Canada, both approaches rely on the measurement of a benchmark return on equity as a point of departure for estimating the return on equity applicable to a particular utility.

[7] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999.

The term "benchmark utility" is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the "benchmark utility" reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve debt ratings in the A category. The typical, average risk, Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's.

Designation of the debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category (See Chapter IV.C for reasons). The estimation of the benchmark return on equity must then be derived from proxy groups whose total risk permits them to achieve debt ratings in the A category.

Both of the approaches described above have been taken by regulators in Canada. The first approach was employed by the National Energy Board (NEB) when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single "benchmark" return on equity could be applied across all of the pipelines. In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk.

It is also the approach that was adopted by the Alberta Energy and Utilities Board (AEUB) in Decision 2004-052 (July 2, 2004). In that decision, the AEUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

In contrast to the NEB and AEUB approach, the British Columbia Utilities Commission has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. The Commission explicitly specifies the low risk benchmark return on equity; each utility's risk premium is expressed in relationship to the low risk benchmark risk premium. It also has designated one utility (Terasen Gas) as the low risk benchmark utility.

In Ontario, the OEB has used both approaches. For the two large gas distribution utilities, the Board historically had approved the same deemed common equity ratios for Enbridge Gas Distribution and Union Gas and allowed a somewhat higher equity risk premium for Union Gas. As a result of its recent settlement (RP-2005-0520, June 29, 2006), Union Gas currently has a somewhat higher equity risk premium and a one percentage point higher deemed common equity ratio. As a result of the Board's Reasons for Decision in EB-2005-0544 (September 20, 2006), Natural Resource Gas is allowed a higher common equity ratio and a higher equity risk premium than either Enbridge or Union. For the electricity distribution utilities, from 2000-2006 the Board allowed a range of deemed common equity ratios using size of rate base as the distinguishing risk factor and applied the same return on equity to each of the utilities.

In my opinion, both approaches are valid as long as the combination of capital structure and return on equity for a particular utility reasonably compensates for the shareholders for the utility's combined business risk and financial risks relative to that of its peers.

For OPG, I have relied on the approach that was adopted by the OEB for electricity distributors in 2000, and by the NEB (1995) and AEUB (2004). Specifically, I estimated a benchmark return on equity and then determined the deemed capital structure for OPG's regulated operations that is compatible with its business risks, would permit it to achieve the same debt rating on a stand-alone basis as the utilities used to estimate the benchmark return, and would equate its level of total business and financial risks to those of the proxy samples.

B. APPROACH TO ESTIMATION OF BENCHMARK RETURN ON EQUITY

To ensure that the allowed return considers all of the relevant factors that bear on a fair return, I recommend application of the three tests that have traditionally been used to set a fair return for regulated companies: the equity risk premium test, the discounted cash flow test and the comparable earnings test. Reliance on multiple tests recognizes that no one test produces a definitive estimate of the fair return.[8] Each test is a forward-looking estimate of investors' equity return requirements. However, the premises of each of the three tests differ; each test has its own strengths and weaknesses. In principle, the concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unreasonable to view it as such.

Moreover, the three criteria that define a fair return, set forth in Chapter II.A, give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. A fair and reasonable return gives weight to both the cost of attracting capital Standard and comparable earnings standard.[9] The two standards are applied using different tests. The equity risk premium and discounted cash flow tests establish the cost of attracting capital. The comparable earnings test is a measure of the comparable return, or comparable earnings, standard. To establish the benchmark return on equity, I have applied all three. The application of each of the tests is discussed in the sections below.

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[8] As stated in Bonbright, "No single or group test or technique is conclusive." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, Va.: Public Utilities Reports, Inc., March 1988).
[9] Appendix B discusses the distinctions between the two standards.

C. EQUITY RISK PREMIUM TESTS

C.1. Conceptual Underpinnings

The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. The equity risk premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

The equity risk premium test, similar to the other tests used to arrive at a fair return, is forward-looking, that is, it is intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks[10] and their views of such key factors as inflation, productivity and profitability. Because the risk premium test is forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

[10] To illustrate, equity market volatility has picked up significantly in 2007, as investors have become less sanguine about the future of the equity market, in light of the recent housing market and sub-prime mortgage market crises. The VIX index, an equity volatility index calculated by the Chicago Board Option Exchange (often referred to as the "Fear Gauge"), indicates that, during much of 2004-2006, the equity market was perceived as unusually stable; that is no longer the case. The VIX index has been rising throughout 2007, increasing by approximately 150% from the beginning of the 2007 to the middle of the 4th Quarter, with much of the increase in the latter half of the year. During November of 2007, the VIX index reached its highest levels since 2003. An increase in the VIX index signals rising risk aversion and an increase in the required equity risk premium.

C.2. Risk-Free Rate

The application of the equity risk premium tests requires a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable. The risk-free rate, for purposes of this analysis, is the forecast 30-year Canada yield which is based on the consensus forecast for 10-year Canada bonds plus the spread between 10- and 30-year Canada bond yields.[11] *Consensus Forecasts*, Consensus Economics (August 13, 2007) anticipates that the 10-year yield will be approximately 4.7% by November 2007 and 5.0% by August 2008 (average of 4.85).

At the end of August 2007, the yield curve was relatively flat; the yields on 10- and 30-year bonds were only approximately 10 basis points apart. On average, historically, the spread has been a positive 30 basis points, reflecting a normal upward sloping yield curve. For purposes of applying the equity risk premium test for the test period, I have estimated the 30-year Canada bond yield at approximately 5.0%, reflecting a continuation of a relatively flat yield curve.[12]

C.3. Risk-Adjusted Equity Market Risk Premium Test

C.3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required utility equity risk premium entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment required for a benchmark Canadian utility; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the equity risk premium required for a benchmark Canadian utility. The cost of equity is thus estimated as:

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[11] There is no consensus forecast of 30-year Canadian bond yields.
[12] The long-term Canada bond yield (and resulting ROE) will be updated for the most recent available forecast prior to the hearing.

$$\begin{matrix}\text{Risk-} \\ \text{Free} \\ \text{Rate}\end{matrix} + \left\{\begin{matrix}\text{Relative} \\ \text{Risk} \\ \text{Adjustment}\end{matrix} \quad \times \quad \begin{matrix}\text{Market} \\ \text{Risk} \\ \text{Premium}\end{matrix}\right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure what an equity investor should require as a return within the context of a diversified portfolio. Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market, as proxied in Canada by the S&P/TSX Composite, and individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing sole reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Appendix C.

C.3.b. Equity Market Risk Premium

C.3.b.(1) Globalization

My estimate of the expected/required equity market risk premium was made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but should also take into account the U.S. equity market as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

The historic Canadian equity and government bond returns incorporate various factors that make them questionable as a realistic representation of future risk premiums (e.g., capital held captive in Canada as a matter of policy, lack of equity market liquidity and diversity, and the higher risk of the Government of Canada bond market historically, which has since dissipated).

Of particular importance has been the historic impact of the Foreign Property Rule (FPR), which capped the proportion of foreign investment that could be held by individuals (in RRSPs) and by pension funds. The combination of mediocre returns and small size of the Canadian market relative to the total global market (approximately 2%) put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. This cap has been as low as 10% of the book value of assets (from 1971 to 1990) and was at 30% when it was removed entirely in August 2005 effective January 1, 2005.[13] Historic Canadian equity returns therefore are likely to understate investor return requirements.

The investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada has grown rapidly as the barriers to foreign investment (in terms of both transactions and information costs as well as the foreign investment cap) have declined. Foreign stock purchases by Canadians have increased over seven-fold over the past decade. Purchases in 1995 were $83 billion; in 2006, they were $570 billion.[14] In 2006, although the total percentage of foreign assets in the top 100 Canadian pension funds was only 33%, the percentage of foreign equity to total equity was close to 56%.[15] While the FPR was in effect, pension funds concentrated their foreign investment allocations to the equity markets, with the preponderance of their fixed income allocations to domestic bonds.

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[13] From 1957 to 1971 no more than 10% of income could come from foreign sources.

[14] The IFIC's report "Year 2002 in Review" stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[15] Benefits Canada, "2007 Top 100 Pension Funds", May 2007.

The relevance of the U.S. experience to the estimation of the risk premium from a Canadian perspective has increased as the relationship between Canadian and U.S. interest rates has changed. From 1947-2006, the achieved risk premiums in Canada were 140 basis points lower than in the U.S. Of that amount, approximately 80 basis points are accounted for by historically higher bond yields in Canada. With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bonds that existed historically, on average, is not expected to persist in the future.

The most recent consensus of long-term forecasts of government bond yields anticipates that yields will be slightly lower in Canada than in the U.S. in the future. Consensus Economics, *Consensus Forecasts,* April 2007 anticipates an average 10-year government bond yield over the period 2009-2017 of 5.1% for Canada and 5.25% for the U.S.[16] With lower interest rates in Canada, the differential between equity and bond returns in the two countries should, *ceteris paribus*, be closer in the future than it was historically. Consequently, the U.S. historic equity market risk premium is a relevant benchmark in the estimation of the forward-looking equity market risk premium for Canadian investors.

On the equity side of the equation, the Canadian equity market composite is dominated by two sectors, financial services and energy. These two sectors alone accounted for approximately 58% of the total market capitalization of the S&P/TSX Composite at the end of August 2007. In contrast to the S&P/TSX Composite, the historic U.S. equity returns have been generated by a more diversified and liquid market. In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Approximately 50% of Canadian portfolio investment in foreign equities at the end of 2006 was in the U.S.[17] The

[16] Blue Chip *Financial Forecasts* (June 2007), which canvasses economic forecasters at over 50 North American financial institutions, anticipates a 10-year U.S. Treasury yield of 5.15% from 2008-2017.

[17] Source: Statistics Canada, *Canada's International Investment Position – First Quarter 2007*. Of the remaining 51%, the next largest allocation of foreign portfolio equity investment is the U.K., which accounted for 13%.

diversified nature of the U.S. equity market and the close relationship between the Canadian and U.S. capital markets and economies warrant giving significant weight to U.S. historical equity risk premiums in the estimation of the required equity risk premium for a benchmark Canadian utility.

C.3.b.(2) The Post-World War II Period

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, I focused on post-World War II returns, that is, 1947-2006, a period more closely aligned with what today's investors are likely to anticipate over the longer-term.[18]

C.3.b.(3) Historic Risk Premiums

As previously indicated, in arriving at an estimation of the market risk premium, my point of departure was both Canadian and U.S. historic returns and risk premiums during the post-World War II period. The average U.S. and Canadian historic risk premiums during that period were as follows:

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[18] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

Table 1

Historic Average Risk Premiums (1947-2006)		
	Arithmetic	**Geometric**
Canada	5.5%	4.7%
U.S.	6.9%	6.1%

Source: Schedule 3.

In light of the increase in Canadian investors' purchases of U.K. equities,[19] I also looked at the historic U.K. indicated market risk premiums over the same period. The U.K. historic premiums were in the range of 6.0% to 6.3% (geometric and arithmetic averages respectively) from 1947-2006 (see Schedule 3).

C.3.b.(4) Superiority of Arithmetic Averages

When historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages, not geometric (compound) averages, should be used. The geometric average, which is appropriate for use in describing historic portfolio performance, represents the achieved return as if it had been a constant average annual return. Using the arithmetic average of all past returns recognizes the probability distribution of future outcomes based on past variations in annual returns. Expressed simply, the arithmetic average recognizes the uncertainty in the stock market; the geometric average removes the uncertainty by smoothing over annual differences.

[19] In 1995, U.K. equities represented only 4.5% of all foreign equities purchased by Canadian investors. In 2005 and 2006, they represented 53% and 23% respectively. Purchases of U.S. and U.K. equities, in total, accounted for 76% of all foreign equities purchased by Canadian investors in 2006 (Statistics Canada).

C.3.b.(5) Future vs. Historic Risk Premiums

The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

I have analyzed the trends in P/E ratios, equity market returns, and bond returns.[20] Briefly, that analysis demonstrates:

- ♦ The increase in price/earnings ratios experienced during the market bubble of the 1990s has not resulted in a higher and unsustainable level of equity market returns. The arithmetic average equity returns in both Canada and the U.S. from 1947-1989 (prior to the "bubble") are actually higher than the average returns for the full 1947-2006 period.
- ♦ An analysis of non-overlapping 10-year average equity returns reveals no upward or downward trend in equity market returns in Canada or the U.S. over the post World War II period.
- ♦ The observed decline in the experienced risk premium is due to the unsustainable increase in bond returns, not a decline in equity returns. The observed historic bond returns are significantly higher than a reasonable estimate of future bond returns (that is, forecast yields of long Canada bond yields).

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.25%, based on

[20] See Appendix C for further discussion.

both the Canadian and U.S. equity market returns (see Appendix C). Based on both the near-term and the longer-term forecasts for long Canada bond yields of 5.0% (2008) and 5.25% (average of 2009-2017),[21] and an expected equity market return of 11.5-12.5%, the indicated Canadian equity market risk premium would be in the range of 6.5-7.25%.[22]

C.3.b.(6) Estimate of Equity Market Risk Premium

Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages, and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.5%. This estimate explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

C.3.c. Relative Risk Adjustment

C.3.c.(1) Total Market Risk

The market risk premium result needs to be adjusted to recognize the relatively lower risk of utilities. The relative risk adjustment that is applicable to a benchmark Canadian utility is approximately 0.65-0.70, based on total risk as measured by standard deviations of market returns and adjusted betas.

My analysis of the relative risk adjustment starts with a recognition that investors are not perfectly diversified, do look at the risks of individual investments, and require compensation for assuming company-specific or investment-specific risk. It also recognizes that, while investors

[21] Consensus Economics, *Consensus Forecasts*, April 2007 anticipates the 10-year Canada bond yield to average approximately 5.1% from 2009 to 2017. Adding a spread of approximately 10 (as of August 2007) to 30 (historic average) basis points to the 5.1% forecast results in a 30-year Canada bond yield forecast of close to 5.25%.

[22] 11.5% - 5.0% = 6.5%
12.5% - 5.25% = 7.25%

can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot. Thus, a risk measurement that reflects those considerations is relevant for estimating the utility equity risk premium. These considerations support focusing on total market risk, as well as on beta, which is intended to measure solely non-diversifiable risk. The drawbacks of beta as the sole measure of risk, as well as the absence of an observable relationship between "raw" betas[23] and the achieved market returns on equity in the Canadian market, provide further support for reliance on other measures of risk to estimate the required equity return (see Appendix C).

The standard deviation of market returns is the principal measurement of total market risk. To compare the relative total risk of Canadian utilities, I calculated the monthly standard deviations of total market returns for each of the 10 major Sectors of the S&P/TSX Index, over recent five-year periods ending 1997 through 2006 (Schedule 5).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 5 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a benchmark Canadian utility in the range of 0.55-0.74, with a central tendency of approximately 0.65-0.70.

[23] The "raw" beta refers to the simple regression between the monthly percentage changes in the price of a utility or utility index and the corresponding percentage change in the price of the equity market index (the S&P/TSX Composite).

C.3.c.(2) Historic Raw Betas

Since beta remains the risk measure that underpins the application of the Capital Asset Pricing Model (CAPM) (of which the risk-adjusted equity market risk premium test is a variant), I also considered betas in arriving at the estimated relative risk adjustment for a benchmark utility. Schedule 8 summarizes "raw" betas for individual publicly-traded Canadian regulated electric and gas companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector over five-year periods ending 1993 through 2006.[24]

As Schedule 8 indicates, there was a significant decline in calculated "raw" betas between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative) followed by an increase in 2006 to the 0.25 to 0.35 range. The observed levels of "raw" utility betas in 1999-2006 can be traced to three factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the negative impact of rising interest rates on utility stock prices while the equity market composite is otherwise increasing (e.g., during the "bubble" of 1999 and early 2000 and during the first half of 2006).

Chart 1 in the Statistical Exhibit graphically demonstrates the "decoupling" between utility stocks and the S&P/TSX Composite between 1999 and mid-2002 period, when the equity market "bubble and bust" was most prevalent. As a result, the disparate movements in utility equities relative to the S&P/TSX Composite during this period produced lower measured utility betas.

Chart 1 also shows that, beginning in mid-2002, the equity market composite and the utility equities began to once again exhibit a correlation that, graphically, resembled more closely the

[24] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector, and no longer comprise a separate sub-index.

typical relationship observed prior to the market "bubble and bust". Utility betas calculated over recent periods that largely eliminate the "bubble and bust" period are higher than those that include data from this period. However, rising interest rates in early 2006 and the resulting negative impact on utility stock prices has again reduced the calculated "raw" utility betas (Schedule 9).[25]

The decoupling between utility shares and the rest of the market during both the technology "bubble and bust" and the first half of 2006 should not be interpreted as a change in the relative riskiness of utility shares,[26] but rather as an indication of the weakness of beta as the sole measure of the relative equity return requirement, particularly within the Canadian equity market context.[27]

[25] Calculated with Nortel excluded from the Composite to remove any lingering effects on the behaviour of the Composite.
[26] Schedule 7 shows that utilities were not the only companies whose betas were negatively impacted by the speculative bubble and subsequent market decline. To illustrate, the 60-month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87.
[27] For example, with the rise in energy stock prices the 60-month betas for the S&P/TSX Energy Sector rose from 0.17 in 2004, to 0.48 in 2005 to over 1.0 in 2006 suggesting a five-fold increase in risk for these companies. (Schedule 7)

C.3.c.(3) Impact of Interest Sensitivity on Relative Risk

Utilities are interest-sensitive stocks and thus tend to move with interest rates, which frequently move counter to the equity market. Consequently, utility equity price movements are correlated not only with the stock market, but also with movements in the bond market. Thus, the interest-sensitivity of utility shares is not fully captured in the calculated "raw" betas, which simply measure the covariability between a stock and the equity market composite.[28] An analysis of the relative historic sensitivity of utility shares to both interest rates and the equity market indicates a relative risk adjustment of close to 80% (see Appendix C).

C.3.c.(4) Use of Adjusted Beta

The deficiencies in "raw" beta can be mitigated by using adjusted betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0.[29] Use of adjusted betas implicitly recognizes that "raw" utility betas do not adequately explain utility returns. For example, as illustrated above, "raw" betas do not capture utilities' interest rate sensitivity. Further, the objective of the relative risk adjustment is to predict the investors' required return. Since utility returns have consistently been higher than what raw betas would indicate, adjusted betas are better predictors of utility returns than "raw" betas.[30]

[28] In theory, the beta should be measured against the entire "capital market" including short-term debt securities, bonds, real estate, etc. In practice, it is measured using the equity market only.

[29] *Value Line*, Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

[30] More generally, a number of empirical studies on CAPM have shown that the return requirement is higher (lower) for a low (high) beta stock than the CAPM would predict.

Table 2 below summarizes the average of the adjusted five-year betas ending in 1993 to 1998 (pre-"Nortel effect") and those calculated over various periods subsequent to the market "bubble and bust".[31]

Table 2

Canadian Utility Adjusted Betas			
Periods	**Individual Canadian Utilities (Median)**	**TSE 300 Gas/Electric Utility Index**	**S&P/TSX Utilities Index**
Five-Year Betas ended 1993 to 1998 (Average)	0.65	0.66	0.73
42-Month Betas (7/2002 to 12/2005)[1/]	0.68	N/A	0.69
30-Month Betas (7/2003 to 12/2005)[1/]	0.66	N/A	0.71
60-Month Betas (7/2002 to 7/2007)	0.63	N/A	0.56

[1/] Excludes Nortel from the Composite.

Source: Schedules 8 and 9.

The adjusted betas indicate a relative risk adjustment of approximately 0.65-0.70.

C.3.c.(5) Relative Risk Adjustment

Based on the preceding analysis of standard deviations of market returns and betas, in my opinion, the relative risk adjustment for a benchmark low risk utility is approximately 0.65-0.70.

[31] Adjusted utility beta = 2/3 ("raw" beta) + 1/3 (market beta of 1.0).

C.3.d. Benchmark Utility Equity Risk Premium

I previously estimated the equity market risk premium at the long Canada yield of 5.0%, at approximately 6.5%. At an equity market risk premium of 6.5% and a relative risk adjustment of 0.65-0.70, the indicated benchmark utility equity risk premium is approximately 4.25-4.50%.[32]

C.4. Utility-Specific Equity Risk Premium Analysis

The risk-adjusted equity market risk premium test (discussed above) estimates the required utility equity risk premium indirectly. That is, it estimates an equity risk premium for the equity market as a whole, and then adjusts it for the relative risk of a benchmark utility. The following analyses estimate the equity risk premium for a benchmark utility directly, by analyzing utility equity return data. The analyses below focus on both long-term historic utility equity risk premiums and an equity risk-premium test derived from forward-looking monthly estimates of the required utility equity return.

The following two sections provide the results of that analysis.

C.4.a. Historic Utility Equity Risk Premiums

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

Over the longer-term (1956-2006),[33] achieved utility equity risk premiums were 4.1-4.8% for Canadian electric and gas utilities, based on geometric and arithmetic average returns

[32] (0.65-0.70) x 6.5% = 4.25-4.50%

respectively.[34] For U.S. electric utilities, the corresponding geometric and arithmetic average historic equity risk premiums were approximately 4.5-5.2% over the entire post-World War II period (1947-2006). The corresponding risk premiums for U.S. gas utilities were 5.5-6.2% (Schedule 10).

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns, as summarized for Canadian utilities in the table below.

Table 3

Average	**Canadian Utility Risk Premiums 1956-2006**		
	Utility Equity Returns	**Bond Returns**	**Achieved Risk Premiums**
Arithmetic	12.6%	7.8%	4.8%
Geometric	11.5%	7.4%	4.1%

Source: Schedule 10.

An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns (Schedule 11); the utility returns in both the U.S. and Canada have clustered in the approximate range of 11.0-12.0%. However, as noted in Appendix C, the bond returns have risen over the fifty-year period to a level that cannot persist, given the low level of interest rates. The low level of interest rates limits further capital gains on bonds (which have given rise to the high observed bond returns in recent years). The best estimate of the expected bond return is the forecast yields on long Canada bond yields, which are in the range of 5.0-5.25%, based on

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[33] The longest period for which Canadian utility data are available from the TSE.
[34] Based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2006.

both near-term and long-term forecasts. When that yield is compared to a utility equity return of 11.0-12.0%, the indicated equity risk premium is approximately 6.0-6.75%.[35]

Focusing on the arithmetic average risk premiums, and recognizing that historic bond returns overstate the expected bond return, the experience of Canadian and U.S. utilities supports an expected equity risk premium estimate for a benchmark Canadian utility in the approximate range of 5.0-5.5%.

C.4.b. DCF-Based Equity Risk Premium Test

A forward-looking equity risk premium test was also performed, using the discounted cash flow model (DCF) to estimate expected utility returns over time. Monthly cost of equity estimates were constructed for the period 1993-2007 (2nd Qtr)[36] using the DCF model and a sample of low risk U.S. electric and gas utilities as a proxy for a benchmark Canadian utility.[37] The reasons for choosing U.S. utilities are as follows:

First, there are an insufficient number of forward-looking estimates of long-term growth rates for Canadian utilities that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums from Canadian data. A consensus estimate of investors' growth expectations is key to the application of the discounted cash flow model. The availability of a consensus of analysts' forecasts means that the resulting growth estimate reflects the market view.

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[35] 11.0% - 5.0% = 6.0%
12.0% - 5.25% = 6.75%

[36] The period 1993-2007 (2nd Qtr) encompasses a full business cycle. It also represents the period of Open Access (implemented via FERC Order 636) for gas distributors which make up close to 50% of the benchmark low risk utility sample.

[37] The selection criteria for the proxy utilities and the construction of the DCF estimates are described in Appendix D.

Second, U.S. and Canadian utilities are reasonable proxies for one another, particularly in today's global capital market. Although there may be company-specific differences in business and financial risk, the impact of those differences is minimized by selecting only relatively pure-play U.S. utilities with similar debt ratings to the typical Canadian utility. The selected U.S. utilities are of relatively low business risk; the sample, which is limited to utilities with debt ratings in the A category, is of similar total risk to a benchmark Canadian utility.

The DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[38] plus the expected dividend yield. The equity risk premium is equal to the difference between the average DCF cost of equity for the sample and the corresponding 30-year Treasury yield for the period.

For the sample of U.S. utilities, the DCF-based risk premium test indicates an average risk premium over the 1993-2007 (2nd Qtr) period of 4.0% (Schedule 12); the corresponding average long-term government bond yield was 5.8%, approximately 75 basis points higher than the test period forecast yield on long Canada bond yields of 5.0%. I also looked at the average risk premium over the period 1998-2007 (2nd Qtr), representing the period subsequent to open access for electric utilities in the U.S.[39] The average risk premium over that period was 4.5%, with a corresponding government bond yield of 5.3%.

The data suggest that there has been an inverse relationship between the risk-free rate (as proxied by the long-term government bond yield) and utility equity risk premiums. To test the relationship between interest rates and risk premiums, a simple regression analysis between the monthly 30-year Treasury yields and the corresponding equity risk premiums over the entire

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[38] The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

[39] Open access for electric utilities was implemented via FERC Order 888 in 1997.

1993-2007 (2nd Qtr) period was conducted.[40] At the test year forecast 30-year government bond yield of 5.0%, the indicated utility equity risk premium is approximately 4.5%.

The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' perception of risk.[41] Thus, I also tested the relationship between the spreads between long-term utility and government bond yields in conjunction with the change in the yield on long-term government bond yields.

To estimate this relationship, I performed a regression analysis over the 1993-2007 (2nd Qtr) period using the utility risk premium[42] as the dependent variable, with the corresponding long-term government bond yield and spread between long-term A-rated utility[43] and government bond yields as the two independent variables.[44] The analysis indicated that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields. The spread between long-term Canadian A-rated utility bonds and 30-year Canada bond yields was approximately 130 basis points at the end of August 2007, compared to the average Moody's A-rated utility/30-year Treasury spread of 139 basis points over the entire 1993-2007 (2rd Qtr) period. Using a forecast long Canada yield of 5.0% and an A-rated utility bond/long Canada spread of 130 basis points, the indicated utility risk premium is 4.3%.

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[40]

Equity Risk premium	=	7.56 – 0.606 (30-Year Treasury yield)
t-statistic	=	-11.0
R^2	=	41%

[41] Or, alternatively, willingness to take risks.
[42] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[43] Based on Moody's long-term A- rated utility bond index.
[44]

Utility Risk Premium	=	4.9 - 0.41 TY + 1.12 Spread
Where,		
TY	=	30-year Treasury Yield
Spread	=	Spread between A-rated Utility Bond Yields and 30-year Treasury Yields
R^2	=	80%
t-statistics:		
Long term bond yield	=	-12.2
Utility/government bond yield spread	=	18.2

Based on both the one and two independent variable approaches, the DCF-based risk premium test results indicate a utility equity risk premium in the range of approximately 4.25-4.50%, at a long-term Canada bond yield of 5.0%.

C.5. Equity Risk Premium Test "Bare-Bones" [45] Cost of Equity

The estimated equity risk premiums for a benchmark Canadian utility based on the three methodologies are as follows:

Table 4

Risk Premium Test	Risk Premium
Risk-Adjusted Equity Market	4.25-4.50%
Historic Utility	5.0-5.50%
DCF-Based	4.25-4.50%

On balance, the three risk premium tests indicate an equity risk premium applicable to a benchmark Canadian utility of 4.25-5.25%, or approximately 4.75%. At a forecast long Canada yield of 5.0%, the "bare-bones" cost of equity is 9.25-10.25% (mid-point of 9.75%).

D. DISCOUNTED CASH FLOW TEST[46]

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the

[45] "Bare-bones" means that this is the market-derived cost of equity before any adjustment to allow for financing flexibility.
[46] See Appendix E for a more detailed discussion.

investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows.

Although the DCF test, like the equity risk premium test, has flaws, it has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM indirectly estimates the cost of equity. The DCF model provides a widely used alternative to the CAPM; it is the principal model utilized by U.S. regulators.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. In determining the DCF cost of equity for a benchmark utility, I utilized both a constant growth and a two-stage model.[47] In both cases, the discounted cash flow test was applied to a sample of low risk U.S. "pure-play" electric and gas distributors that are intended to serve as a proxy for a benchmark Canadian utility.[48]

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.)

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[47] The two-stage model is a form of multiple period model; please see Appendix E for discussion of the DCF models used; the criteria for the low risk U.S. utility sample selection are described in Appendix D.

[48] Reliance on U.S. utilities was explained in the discussion of the DCF-based equity risk premium test in Chapter III.C.4.b.

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. Thus, in applying the DCF test, I relied solely on published forecast growth rates that are readily available to investors. The constant growth model uses the consensus of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations. The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year 6 onward) to migrate to the expected long-run rate of nominal growth in the economy.

The results of the constant growth and two-stage DCF models indicate a required "bare-bones" return on equity of approximately 9.25-9.5% (Appendix E and Schedules 14 and 15). It is important to recognize that the 9.25-9.5% DCF cost represents the return investors expect to earn on the current market value of their utility common equity investments. It is not, however, the return that investors expect the utilities to earn on the book value of their common equity. *Value Line*, which publishes its projections of utility ROEs quarterly, anticipates that the return on average common equity for the sample of low risk U.S. utilities over the period 2010-2012 will be approximately 11.2-12.0% (Schedule 13).

E. ALLOWANCE FOR FINANCING FLEXIBILITY[49]

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle.

[49] See Appendix G for a more complete discussion.

In the absence of an adjustment for financial flexibility, the application of a “bare-bones” cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite has averaged 2.1 times over the past business cycle (1994-2006); the corresponding average market/book ratio of the S&P 500 has been 3.4 times.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[50] As this financing flexibility adjustment is minimal, it does not fully address the comparable return standard.

The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators. As a government-owned utility, OPG has not raised equity capital in the public equity markets; therefore it does not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the cost of equity and a fair return on the book value of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership. The Board has implicitly recognized this principle in the past (e.g., in its Transitional Rate Order (Distribution) for Hydro One, RP-1998-0001), by setting returns for the government-owned utilities that are comparable to those allowed for investor-owned utilities.

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[50] Based on the DCF model; see Appendix G for calculation.

The addition of an allowance for financing flexibility of 50 basis points to the "bare-bones" return on equity estimate of 9.25-10.25% derived from both the DCF and equity risk premium tests respectively, results in an estimate of the fair return on equity of 9.75%-10.75%.

F. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable earnings standard, as distinguished from the cost of attracting capital standard. The comparable earnings standard recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the cost of attracting capital standard relies on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable earnings standard, as well as the principle of fairness, suggests that, if competitive industrial firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable earnings standard when setting a just and reasonable return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. To illustrate, if the market value of an investment is $15 and the required return is 10%, the return, <u>in dollars</u>, expected by investors is $1.50. However, regulatory convention applies the market-derived return to the book value of the investment. If the book value of the investment is $10.00, application of a 10% return to the book value will result in a return, <u>in dollars</u>, of only $1.00. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value.[51] The comparable earnings test, however, does. It applies "apples to apples", i.e., a book value-measured return is applied to a book value-measured equity investment.

[51] As previously noted, the 50 basis point financing flexibility adjustment is only a minimal recognition of the discrepancy.

The principal issues in the application of the comparable earnings test are:[52]

- The selection of a sample of industrials of reasonably comparable risk to a benchmark Canadian utility.
- The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.
- The need for any adjustment to the "raw" comparable earnings results if the selected industrials are not of precisely equivalent risk to the benchmark utility.
- The need for a downward adjustment for the industrials' market/book ratios.

The application of the comparable earnings test first requires the selection of one or more samples of industrials of reasonably comparable risk to a benchmark Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of samples of industrial companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, stock and bond ratings and betas (See Appendix F).

Since the universe of Canadian industrial companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. However, a sample of U.S. companies was also used as a check on the reasonableness of the Canadian sample results. The application of the selection criteria to the Canadian universe produced a sample of 20 companies.

Next, since industrials' returns on equity tend to be cyclical, the selection of an appropriate period for measuring industrial returns must be determined. The period selected should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be

[52] Full discussion in Appendix F.

similar in terms of inflation and real economic growth.[53] The period 1994-2006 provides a reasonable proxy for a future business cycle, as the experienced rates of inflation and economic growth are reasonably similar to the rates projected by economists over the next business cycle. The experienced returns on equity of the sample of 20 Canadian low risk industrial companies over this period were in the approximate range of 12.75-13.25% (see Appendix F and Schedule 17).

The next step is to assess whether or not there is a need to adjust the "raw" comparable earnings results to reflect the differential risk of a benchmark Canadian utility relative to the selected industrials. The comparative risk data (including betas and stock and bond ratings) indicate, on balance, the Canadian industrials are of modestly higher risk than a benchmark utility. To recognize the industrials' higher risk, the comparable earnings test results require a downward adjustment to a range of 12.25-12.75% (mid-point of 12.50%).

Since the Canadian sample is relatively small, in large part a function of the size and make-up of the Canadian equity market, as noted above, I also selected a sample of low risk U.S. industrials to serve as a check on the reasonableness of the Canadian results. The selection criteria were virtually identical to those used for the Canadian industrial sample. The greater breadth of the U.S. market allowed the selection of a sample of 157 companies in the same stable industries used to select the Canadian industrials. The experienced returns of the U.S. industrials were in the range of 13.5-14.5% (see Schedule 19). The comparative risk data indicate that the U.S. industrials are of relatively similar risk to the Canadian industrials (see Schedule 18), and thus of slightly higher risk than a benchmark Canadian utility. When used as a check against the Canadian firms, the returns of the significantly larger U.S. sample of industrials underscore the reasonableness of the comparable earnings results for the sample of Canadian industrials.

[53] Returns on equity during earlier periods may not be comparable as the economic fundamentals that impact achievable returns (e.g., inflation) were not comparable.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a relatively high market/book ratio would point to returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratio of the sample of Canadian comparable industrial companies over the 1994-2006 period was 2.1 times, virtually identical to the market/book ratio of the S&P/TSX composite over the same period (see Appendix F). For the U.S. industrial sample, the average market/book ratio for 1994-2006 was approximately 2.7 times, compared to 3.4 times for the S&P 500. The similar to market/book ratios of the proxy samples relative to the market composites indicate no evidence of market power and thus no rationale for a downward adjustment. As a result, a fair return for a benchmark Canadian utility based on the comparable earnings test is approximately 12.5%.

G. FAIR RETURN ON EQUITY FOR A BENCHMARK CANADIAN UTILITY

The results of the three tests used to estimate a reasonable return on equity for a benchmark Canadian utility are summarized below:

Table 5

Test	"Bare-Bones" Cost of Equity	Fair Return on Equity
Equity Risk Premium	9.25-10.25%	9.75-10.75%
Discounted Cash Flow	9.25-9.5%	9.75-10.0%
Comparable Earnings	N/A	12.5%

In arriving at a reasonable return for a benchmark utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. The "bare-bones" cost of attracting capital based on these two tests is approximately 9.25-10.0%. Including the allowance for financing flexibility, the indicated return on equity is 9.75-10.5%. However, the results of the comparable earnings test are also entitled to significant weight when setting a fair return that balances both ratepayer and shareholder interests. Based on all three test results, a fair return for a benchmark Canadian utility is approximately 10.25-10.75% (mid-point of 10.5%). A return on equity of 10.5% is applicable to OPG's regulated operations at a deemed common equity ratio sufficient to equate their total risk (business and financial) to that of the proxies used to estimate the benchmark return.

IV. DEEMED CAPITAL STRUCTURE FOR OPG REGULATED

A. PRINCIPLES

The following principles should be respected when establishing the appropriate capital structure for OPG's regulated operations:

1. The stand-alone principle.
2. Compatibility of capital structure with business risks.
3. Maintenance of creditworthiness/financial integrity.
4. Compatibility with the benchmark return on equity.

Each of these principles is defined below.

A.1. The Stand-Alone Principle

As discussed in Chapter II.B, the stand-alone principle encompasses the notion that the cost of capital incurred by the ratepayers should be equivalent to that which would be faced by each division raising capital in the public markets on the strength of its own business and financial parameters. The cost of capital should reflect neither subsidies given to, nor taken from, other activities of the firm. Application of the stand-alone principle to OPG's regulated operations means that they should be treated as if they were operating separately from the other operations of the firm.

The consolidated operations of OPG are rated by both DBRS and Standard & Poor's. DBRS rates OPG A(low) with a Stable trend and S&P rates OPG BBB+ with a Positive trend. The ratings of OPG on a purely stand-alone basis would be lower if it were not for the perceived support of the Province as shareholder. S&P, for example, has stated that OPG's rating benefits from two notches of government support.[54] In other words, in the absence of the perceived level of government support, OPG's S&P debt rating would be BBB-. Nevertheless, S&P has also stated that

> (I)t is with the potential for changing circumstances in mind that the ratings on Hydro One and OPG are more closely aligned to the underlying creditworthiness of the individual companies than their owner. Governments change, government policies change, views on ownership change, economic circumstances change, and the financial ability and willingness of the province to support its enterprises can change also.
>
> Fundamentally, it is not possible to predict the future political willingness to support a separately incorporated entity. Politics by definition is populist, expedient, and capricious, and creditors should not dismiss the likelihood of change. [55]

While DBRS concludes that the current rating is more "reflective of OPG's improved financial profile on a stand-alone basis, which has been driven by a more favourable regulatory environment," they note "that the rating on OPG over the past several years has been supported by the Province of Ontario (the Province, rated AA), OPG's sole shareholder and provider of financial support. The provincial ownership and financial support limited downward movement in OPG's rating to below the A (low) level during prior periods of weak financial performance by the Company...."[56] Although OPG does not currently borrow long-term debt in the public markets, but rather from the Ontario Electricity Financial Corporation (OEFC), the credit spreads for its funding are based on the market debt costs of regulated firms in Canada with similar or better investment grade debt ratings. As a result, ratepayers receive the benefit of a lower cost of debt than would be achievable by OPG in the absence of the perceived government support.

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[54] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.
[55] Standard & Poor's, *Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc.*, October 20, 2005.
[56] DBRS, *Rating Report: Ontario Power Generation Inc.*, August 3, 2006.

This benefit is provided at no cost (i.e., there is no debt fee paid to the Province for the potential financial support). The proper application of the stand-alone principle to the determination of the deemed capital structure (and return on equity) for OPG's regulated operations ignores the happenstance of ownership; the capital structure should reflect the business risks of OPG's regulated operations irrespective of the identity of the shareholder. This approach ensures that the shareholder is properly compensated for the total risk borne.

A.2. Business Risks

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework of the utility that can lead to the failure to recover a compensatory return on, and/or the return of the capital investment itself.

A.3. Maintenance of Creditworthiness and Financial Integrity

The capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings for the regulated operations. An investment grade debt rating provides the basis for access to the capital markets on reasonable terms and conditions. As a corporate entity operating with a commercial mandate to operate on a financially sustainable basis, OPG should be positioned to access the public debt markets. The regulated operations of OPG should contribute their fair share to the creditworthiness and financial integrity of Ontario Power Generation Inc., the corporate entity responsible for raising debt capital on behalf of the entire organization. The importance of investment grade debt ratings is discussed in detail in Chapter IV.C.

A.4. Compatibility with Benchmark Return

The approach I have taken applies a benchmark return on equity to a deemed equity ratio. Thus, the deemed equity ratio needs to be set at a level that, given OPG's business risks, equates the level of OPG's total risks to that of the proxy utilities used to estimate the benchmark return.

B. BUSINESS RISKS

B.1. Conceptual Considerations

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short- and long-term risks. Long-term risks are important because utility assets are long-lived. Because utilities are generally regulated on the basis of annual revenue requirements, there has been a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall the approval of higher returns when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future. Third, if a risk is experienced, the incurrence of costs to address it may create cash flow constraints before appropriate rate relief can be secured.

Business risk, as defined in Chapter II.C, comprises the composite of the operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. It includes the factors that expose the equity shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment. Business risks include market demand, supply, physical/operating and regulatory/political risks. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is generally designed to take account of the specific fundamental market and operating risks faced by the regulated entity.

The following sections discuss the business risks of OPG's regulated operations (or, alternatively, the prescribed assets) in the composite and the hydroelectric and nuclear operations individually.

B.2. Business Risks of the Composite Regulated Operations

B.2.a. Revenue and Market-Related Risks

Market risks for OPG are partly defined by the economy in which it operates. The Ontario economy is the largest in the country, accounting for approximately 40% of population and GDP.[57] Growth in Ontario is expected to exceed that of the country as a whole over the longer-term. The Ontario Ministry of Finance expects real GDP growth in Ontario to average approximately 2.8% from 2010 to 2019, compared to the consensus forecast for Canada as a whole of 2.6% from 2009 to 2017.[58] Strength in the economy over the longer-term is in part expected to arise as a result of a favourable demographic outlook due to sturdy international migration.[59] Challenges to the Ontario economy over the longer-term – and thus to energy demand – include the impact of the high Canadian dollar and high energy prices on global competitiveness of the export-intensive manufacturing sector, which may result in plant closures or retrenchment in key industries. Thus, while the diversity and strength of the economy are positive for the overall business risk assessment of OPG, the challenges to the manufacturing sector expose the regulated operations to some risk of lower revenues due to decreased demand, both from cyclical declines and long-term demand destruction.

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[57] Ontario Financing Authority (www.ofina.on.ca)
[58] Ontario Ministry of Finance, *Toward 2025: Assessing Ontario's Long-Term Outlook,* January 2006.
[59] Consensus Economics, *Consensus Forecasts,* April, 2007.

Revenue risks for OPG's regulated operations also include the impact of weather as well as the potential impact of a provincial energy policy that actively promotes conservation and demand side management. The Ontario government has set targets for energy conservation to produce 6300 MWs of peak electricity savings by 2025 (peak demand in 2006 was 27000 MWs). Reduction in demand driven by conservation exposes the regulated assets to the risk of lower revenues.

Because the prescribed assets are primarily baseload facilities, the revenue risks associated with economic cycles, potential demand destruction and conservation are lower for OPG's regulated operations than those of a typical generator with a portfolio of baseload, mid-merit and peaking facilities.

Competitive risks with other energy sources are not significant, since electricity does not compete to any material extent with alternative energy sources, such as natural gas, due largely to the relative price of electricity. There is some competition for certain electricity uses (e.g., commercial air conditioning, water heating), but it is not considered to be a significant risk.

Counter-party risk is considered to be minor, since OPG's regulated revenue comes from the Ontario Independent Electricity System Operator (IESO), and payment defaults by market participants are first met by drawing upon prudential requirements and then through a default levy on all non-defaulting market participants.

Revenue risks are also a function of the high degree of operating leverage which is characteristic of asset intensive businesses like electricity generation. A high degree of operating leverage means that OPG's costs are largely fixed. All other things held constant, the higher the operating leverage, the higher is the business risk. When costs are largely fixed, but prices are largely consumption or energy-based, a small decline in sales can have a material impact on the firm's operating income and return on equity. OPG's payments are currently 100% energy-based, which means it must recover all of its fixed costs in a variable payment. Most utilities recover a significant proportion of their total fixed costs in a fixed customer charge, demand charge, or capacity payment. For example, the transmission utilities in Alberta collect 100% of their forecast revenue requirement in fixed monthly payments from the Alberta Electric System Operator. Gas pipelines regulated by the National Energy Board collect virtually all of their fixed costs in demand charges from shippers; electricity and gas distributors may collect up to 85% of their fixed costs in customer/capacity charges.[60] Based on the proposed payment structures for the prescribed assets (100% energy-based for hydroelectric assets and a fixed charge for nuclear assets covering 25% of forecast nuclear revenue requirement), OPG would recover approximately 20% of its total regulated costs in a fixed charge. Under this structure, the assurance of recovery of the regulated operations' fixed costs through fixed charges will be less, and the revenue risk higher, than for the typical Canadian utility.

Based on the OPG's rate application, the forecast 2009 information indicates that approximately 85% of OPG's revenue requirement other than return on equity and income taxes is comprised of expenses that are largely fixed (i.e., they do not vary directly with production). As the rate base declines over time, the dollars of return on rate base decline in absolute terms and in proportion to OPG's total fixed costs. In the absence of rate base growth (i.e., based on the existing prescribed assets, absent refurbishment), OPG's high fixed cost structure will continue to increase the sensitivity of the ROE to changes in revenues and expenses.

In contrast to electric and gas distribution utilities and vertically integrated (non-restructured) utilities, OPG does not have a defined franchise area, nor does it have an obligation to serve. The regulated generation competes in the Ontario market with OPG's unregulated generation and the generation owned by or leased by others (e.g. Bruce Power). At present, the competitive/market risks faced by OPG's regulated operations are relatively low, as the prescribed assets are primarily baseload facilities[61], with relatively low variable (marginal) costs

[60] For example, FortisAlberta collects approximately 85% of its fixed distribution costs in customer/demand charges; ATCO Electric Distribution collects approximately 65% of its fixed distribution costs in customer/demand charges.
[61] The Beck complex has some peaking capability.

of production. There are, however, other generators whose marginal costs are similarly low (e.g., Bruce Power, wind generators, Brookfield Power), which can result in OPG's regulated facilities not being dispatched for short periods in which demand is relatively low. Nevertheless, dispatch risk for the regulated assets is currently relatively low. That risk will rise as additional low marginal cost generation (which can bid below cost but receive a price specified in its PPA with the OPA) becomes available or demand drops.

With respect to the impact of market prices on revenue risk, the market wholesale price of electricity in Ontario is set on the basis of supply of and demand for electricity, with the major driving factors being load, generator availability and fuel (e.g., natural gas) prices. OPG's regulated assets do not typically set the market-clearing price, except in cases of unutilized baseload capacity.[62] Since the payments for OPG's regulated generation are expected to reflect the total costs of production, including a reasonable return on invested capital, the revenue requirement is not based on market price factors.

B.2.b. Production, Operating and Cost Recovery Risks

Production, operating and cost recovery risks include all factors that may result in OPG under-recovering a reasonable return on investment and/or a part of the investment itself due to higher than anticipated costs of production, lower than anticipated production or loss of production. These factors are largely specific to the generation technology and are discussed in the individual hydroelectric and nuclear operations sections that follow.

B.2.c. Regulatory Risks

With respect to economic regulation, regulation has the power to expose utilities to enormous risks, by disallowing costs, approving rate structures that are incompatible with the cost

[62] As additional low marginal cost generation becomes available, and the potential for unutilized baseload capacity correspondingly rises, OPG's prescribed assets will increasingly determine the market-clearing price.

structure, or allowing returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility a reasonable opportunity to achieve a fair return. Enlightened regulation will mitigate risks that are not susceptible to managerial control, and award a return that provides both (1) fair compensation for the risks that are left with management and (2) incentives to achieve (and exceed) the allowed return through continued improvement in productivity. The regulatory framework in which a utility operates is frequently viewed as the most significant aspect of risk to which investors in a utility are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

While OPG has been subject to the provisions of Regulation 53/05 since April 2005, the introduction of active regulation by the OEB as of April 1, 2008 creates a number of uncertainties, as the "end state" of regulation is unknown. The November 30, 2006 "*Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*" ultimately envisions an incentive regulation framework, but the parameters of that framework have yet to be developed, and the information necessary to create that framework can be expected to take a number of years to develop. In the interim, OPG's regulated operations will be subject to cost of service regulation. For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's jurisdiction: OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed.

In that context, certain requirements set out in Regulation 53/05 should be viewed as an implementation of the traditional regulatory prohibition against retroactive ratemaking. Those requirements include that:

1) OPG be allowed to recover the costs incurred with respect to the Bruce Nuclear Generating Station;

2) OPG be allowed to recover the costs and firm financial commitments incurred prior to the issuance of the Board's first rate order for the purpose of increasing the output of, refurbishing or adding operating capacity to a prescribed generation facility, if the costs and financial commitments were within the project budgets approved for that purpose by OPG's Board of Directors, and the OEB is satisfied that the costs and financial commitments were prudently incurred;

3) the Board must accept, for purposes of its first order, the values in OPG's most recently audited financial statements with respect to certain matters;

4) OPG be allowed to recover amounts recorded in the Pickering A return to service deferral account;

5) OPG be allowed to recover amounts in the variance accounts established by the regulation, subject to a determination by the OEB that the amounts were prudently incurred and accurately recorded; and,

6) OPG be allowed to recover its ONFA related costs, and to establish a deferral account for that purpose.

Going forward, OPG will be subject to the same standards of oversight with regard to recovery of costs incurred as other utilities regulated by the OEB.

As part of its payment application, OPG is applying to retain several of the deferral and variance accounts established under Regulation 53/05 that relate to future cost incurrence, but to discontinue several of the others. Specifically, OPG is proposing to retain deferral accounts for

ONFA related costs (Nuclear Liabilities Deferral Account) and costs to increase/add or refurbish its generation capacity (Capacity Increases/Additions and Refurbishments Deferral Account). OPG is also proposing to continue the variance accounts for the net revenue impact for variability in hydroelectricity production due to changes in water conditions (Water Conditions Deferral Account) and forecast ancillary service revenues (Ancillary Services Revenue Variance Accounts) . The variance account for transmission outages and restrictions will be eliminated, as will the variance accounts associated with Acts of God and unforeseen changes in nuclear technology or regulatory requirements[63], but OPG has reserved the right to do so in the future should there be material financial consequences arising from these factors. OPG is also proposing several new variance accounts, the most important of which will record the difference between actual and forecast pension/OPEB expense.[64]

The use of deferral and variance accounts can mitigate forecasting risks related to costs over which the utility has no control, but does not change the utility's fundamental risks. Moreover, the ability to create a variance or deferral account and accrue differences between forecast and actual costs does not guarantee recovery of those costs. The extent to which deferral accounts lower the forecasting risk faced by a utility and thus cost of capital is a function of the scope of the accounts and the materiality of the costs that are covered by those accounts.

All utilities have the ability to apply to the regulator for deferral accounts. The OEB has demonstrated an inclination to establish deferral accounts and recover costs accrued therein, subject to criteria of prudence, materiality, causation and uncontrollability. Therefore, OPG's

[63] The variance accounts established for ancillary services (to be continued) and transmission outages and restrictions (to be eliminated), while they relate to revenues and costs beyond the control of management, the amounts are minor relative to the total revenue requirement and thus have little or no impact on the level of business risk.

[64] The potential variance between actual and forecast pension/OPEB expense is significant, primarily due to changes in the discount rate. A 25 basis point change in the discount rate used to establish the expense can alter expense by $50 million. OPG proposes to accumulate differences between actual and forecast expense in a variance account, but the amounts in the account would not be cleared until the cumulative balance (positive or negative) in the account reaches $100 million.

ability to recover its actual costs as a result of access to the existing deferral accounts does not result in a reduction in its risk relative to that of other utilities.

On balance, I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario. As the Board suggested in its November 20, 2006 report, the application of cost of service regulation to generation is a relatively unique phenomenon, with no track record upon which to gauge the outcome. The uncertainty of the "end state" is amplified by the fact that OPG will be regulated in a market environment which is a hybrid of regulation and competition, which creates additional pressure on regulated rates in a period of potentially significant cost increases (e.g., decommissioning costs, other post-retirement benefit expenses).

Further, OPG potentially faces significant capital expenditures for regulated facilities for which it may require regular access to debt markets. The requirement to refurbish existing nuclear plants, or build new nuclear or large scale hydroelectric generation facilities would entail an extended period between development, construction and putting those assets into service.

In this regard, traditional utility practice has been to exclude assets from rate base until they are used and useful and to accrue an Allowance for Funds Used During Construction (AFUDC) to recognize the financing costs incurred while the assets are being constructed. The AFUDC is capitalized and added to the cost of the assets and recovered after the assets are placed into service.[65] The exclusion of Construction Work in Progress (CWIP) from rate base is potentially a major disincentive to utilities to undertake the construction of major projects.[66] Allowing

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[65] Depending on the jurisdiction, the AFUDC rate may be an interest rate or the weighted average cost of capital. In Ontario, while the OEB has previously recognized that it is appropriate to use a weighted average cost of capital (WACC) for purposes of calculating AFUDC, it has recently approved the use of a medium term interest rate to be applied to Construction Work in Progress for distribution utilities. The implication of this decision is that CWIP is 100% debt financed, a conclusion that should be taken into account in determining the allowed capital structure for rate base to ensure that the capital structure underpinning the totality of regulated assets, inclusive of CWIP, contains a reasonable balance of debt and equity.

[66] Recognition of the need to provide incentives to utilities to build needed infrastructure has led the Federal Energy Regulatory Commission to adopt a slate of incentives for transmission utilities that includes allowing CWIP in rate base.

CWIP in rate base in a period of high capital expenditures related to a fundamentally risky generation plant would help mitigate the increase in risks. The inclusion of CWIP in rate base would be viewed as mitigating risk by both debt and equity investors. My recommendation is premised on OPG being allowed to include in rate base CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, such as the Niagara Tunnel. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

With the electricity market environment still in flux, the regulated operations of OPG remain subject to political risk. Since the initial restructuring that began in 1998 with the Energy Competition Act, there have been several interventions by the government into the operation of the electricity market. Ontario is one of the two provinces in Canada in which political intervention in the regulatory process has been a factor in the business risk assessment of utilities by the debt rating agencies (Alberta is the other). Political intervention in the industry restructuring process to shield customers from the impact of rising market prices for power was the principal reason given by the debt rating agencies for their downgrades to the debt ratings in 2003 of Ontario electric utilities. The debt rating agencies view the risk of further political intervention in the Ontario market as having declined since those debt rating reductions occurred in 2003. Nevertheless, the risk of future political intervention in the market is higher than in other Canadian jurisdictions, as there continue to be unresolved issues in an evolving Ontario electricity marketplace. With rising energy prices, the potential for future political intervention cannot be disregarded, as recent experience in the U.S. (e.g., Maryland, Illinois) demonstrates.

B.3. Business Risks of the Hydroelectric Operations

B.3.a. Revenue and Market-Related Risks

Revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. While the costs of the hydroelectric operations are largely fixed, OPG's proposed payment structure for production from its prescribed hydroelectric assets reflects a rate that is 100% energy-based. In isolation, the payment structure exposes OPG to higher revenue risks than the typical regulated company, which recovers a portion of its fixed costs in demand or customer charges.

Revenue risks also include the risk that the hydroelectric assets will not be dispatched. Dispatch risk remains low at present for the hydroelectric assets, as they are largely baseload facilities,[67] with low marginal costs. However, this risk will rise as additional low marginal cost generation becomes available. The emerging risk that OPG's prescribed assets are not dispatched and there will be unutilized baseload capacity will impact the hydroelectric facilities first.

Market prices are expected to directly impact regulated operations only through the operation of proposed hydroelectric incentive mechanism. Under the proposed Hydro Incentive Mechanism, OPG will be financially obligated to supply a given amount of energy each hour (Hourly Volume). It would receive the regulated payment for each MWh up to the Hourly Volume and the market clearing price for each MWh of energy in excess of the Hourly Volume. If OPG fails to supply the Hourly Volume for which it is financially obligated, its payments will be reduced by the difference between the amount supplied and the market price. Although the incentive mechanism and its reliance on market prices do not impact the determination of the revenue requirement (i.e., the revenue requirement is based on the total costs of providing service, not market prices), its operation can impact the recovery of the revenue requirement. While OPG's

[67] As indicated earlier, the Beck complex has some peaking capability.

proposed regulated payments and the incentive mechanism are based on the same underlying forecast revenue requirement, the incentive mechanism has been constructed to operate on a stand-alone basis; that is, the risks/rewards of the mechanism were designed to be self-contained and as such are not incorporated into the business risk assessment of the prescribed hydroelectric assets.[68] Nevertheless, the form of the proposed incentive mechanism exposes the regulated operations to a risk that they will under-recover their revenue requirement.

B.3.b. Production, Operating and Cost Recovery Risks

The principal production risk facing the hydroelectric operations is related to the availability of water. Actual hydroelectric production can differ from long-term averages by close to 10% due to more or less than average water availability. Regulation 53/05 established a variance account to capture differences in hydroelectricity production due to differences between forecast and actual water conditions. Specifically, if the amount of available water is lower than forecast, the variance account is debited for an amount necessary to raise the total costs recovered to the level that would have been recovered had actual water levels been known; similarly the variance account is credited when actual water levels are higher than forecast. This variance account protects OPG's regulated revenues from a factor beyond management control. OPG is still at risk for differences between actual and forecast costs (e.g., shortfalls from targeted cost efficiencies) and differences between actual and forecast production for reasons other than water levels, the latter primarily arising from longer than anticipated outages and to a lesser extent from lower than expected demand (decreased demand would cause hydroelectricity production to be reduced in advance of nuclear production).

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[68] The "*Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*" (EB-2006-0064, November 30, 2006) ("Board Report") has indicated that the form of an incentive mechanism may be an issue. For example, the OEB will examine the current incentive mechanism including the existing threshold of 1900 MWh and the possibility of a separate price mechanism for the Beck pump generation facility. The adoption by the Board of an incentive mechanism that differs materially from that proposed by OPG could change the business risk profile of the regulated hydroelectric operations.

Given the potential differences between forecast and actual water and the resulting impacts on hydroelectric production and cost recovery, the operation of the variance account is a key risk mitigator for OPG. I have assumed the continuation of this mechanism (Water Conditions Deferral Account) as proposed by OPG for purposes of establishing an appropriate capital structure and return on equity.[69] From a relative risk perspective, the hydroelectricity variance account puts OPG on a similar footing to other utilities with significant hydroelectricity generation whose production is subject to water availability.[70]

Other forecasting risks specifically related to hydroelectricity facilities include an emerging risk related to requirements for water taking permits,[71] issues related to land claims or grievances which could result in higher than anticipated costs or interruption in production, and increased costs related to environmental issues (e.g., threatened species or fisheries authorizations).

B.3.c. Regulatory Risks

Chapter IV.B.2.c of this evidence discusses the regulatory environment as it impacts the composite regulated operations of OPG, including the hydroelectric operations. The key element of the regulatory framework that is unique to the hydroelectric operations is the variance account for differences between actual and forecast production due to differences between forecast and actual water conditions. As noted above, I view this variance account as a key risk mitigator, given the potential differences between forecast and actual water and the resulting impacts on hydroelectricity production and cost recovery. I have assumed the continuation of this account

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[69] Going forward, this variance account may have increasing value, as water availability may become more uncertain if weather patterns become more volatile or more extreme with global climate change.

[70] In Canada, for example, Northwest Territories Power has a rate stabilization mechanism that protects against deviations between actual and normal water levels. In the U.S., Idaho Power, whose generating capacity is approximately 44% hydroelectricity-based, is allowed to recover 90% of the difference between forecast and actual purchased power and fuel costs. Puget Energy, whose generating capacity is approximately 11% hydroelectricity-based, has a power cost adjustment mechanism that provides earnings protection outside of a dead-band against various factors that can increase power costs, including water availability.

[71] Legislative changes could require permits to take water for non-consumption purposes, which could require payments for generation-related water flows and which could put limits on source water for hydroelectricity production.

for purposes of establishing an appropriate capital structure and return on equity for OPG's regulated operations.

OPG potentially faces significant capital expenditures to build new large scale hydroelectricity facilities. The requirement to build a new large scale hydroelectric generation facility would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures would help mitigate the corresponding increase in risk. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

B.4. Business Risks of the Nuclear Operations

B.4.a. <u>Revenue and Market-Related Risks</u>

As discussed earlier, revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. Except for the fuel costs, which make up a relatively small proportion of the total nuclear operations' cost structure, the costs of nuclear production are largely (over 90%) fixed. The proposed nuclear payment structure will collect 25% of OPG's forecast revenue requirement in a fixed charge. Under this structure, the assurance of recovery of the nuclear operations' fixed costs through fixed charges will still be less, and the revenue risk higher, than for the typical Canadian utility.

Revenue risks for nuclear operations include the risk that the generating plants will not be dispatched. Dispatch risk is low at present for the nuclear assets, as they are baseload facilities with low marginal costs. The risk to the nuclear operations that there will be unutilized baseload capacity will rise as additional low marginal cost generation becomes available. This is particularly problematic for nuclear generation, given the time required for the plants to ramp production up and down. No allowance for this emerging risk has been included in the forecast production.

The Board Report raises a risk that regulated revenues will be indirectly impacted by the market price, as it raises the spectre of caps on regulated payments if they exceed the market price for an extended period of time. This risk would principally impact nuclear production. Application of a cap based on market prices in the context of cost of service regulation would be an anomalous practice. Given that (1) the interim price for nuclear generation of $49.50 per MWh only included a 5% return on equity, and (2) OPG is facing potentially significant future cost increases (e.g., decommissioning costs), a cap on regulated payments tied to market prices could impair OPG's ability to earn a compensatory return.[72] The risk assessment proceeds on the assumption that the Board will not impose a cap on regulated payments tied to market prices.

B.4.b. Production, Operating and Cost Recovery Risks

The production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities (and are higher than those of any other types of generation).[73] Nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production.

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[72] For some perspective, the weighted average Hourly Ontario Electricity Price was approximately $48.50/MWh during 2006, compared to the price of $53.38 that had been forecast for 2006 in March 2005 by Navigant Consulting in *Ontario Wholesale Electricity Market Price Forecast for the Period January 1, 2006 through December 31, 2006*, largely due to lower than anticipated load and lower than anticipated natural gas prices.

[73] According to Standard & Poor's,

> Nuclear generating assets have significant operational and technology risks. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past. (Standard & Poor's, *Summary: Ontario Power Generation, Inc*., April 24, 2007.)

Forecasts of nuclear facility production include both planned and unplanned outages, and are based on past experience, benchmark data, levels of past and ongoing maintenance, unit reliability factors and the age and condition of individual units and thus reflect the level of production that OPG can reasonably expect to generate. The nuclear operating environment is much harsher than for fossil generation or for hydroelectric generation. As a result, the complexity and length of time for repair of nuclear plants often exceed those of hydroelectric or fossil generation. The nuclear plants may also experience deterioration or shift in physical properties that go beyond what was expected or assumed in the design of the plant. The specific circumstances of OPG entail additional risk, as the reactors reflect different stages of the CANDU design. Ongoing updates to nuclear operating standards and regulations may require modifications to the plants, particularly those with older design reactors, to ensure compliance.

While the forecast costs and production from the nuclear facilities include a provision for both planned and unplanned outages, the operating environment and the technological characteristics of OPG's nuclear generation fleet are such that the extent of required maintenance, repair or refurbishment is 1) forecast with a higher degree of uncertainty than for other types of generation, 2) can result in materially longer than anticipated outages and more frequent and longer than could be expected forced outages, 3) can result in higher than anticipated costs of repair or remediation, and 4) potentially lead to permanent loss of production either as a result of derating or a premature end of the economic life of the plant.[74]

Other production-related risks to nuclear production include weather damage and the threat of increased algae runs (which restrict cooling water intake flows). With respect to the latter, algae runs become more problematic as average temperatures rise over time. Further, as average temperatures rise, it becomes more difficult to cool the reactors. Thus, nuclear stations are more significantly affected by external conditions (e.g., cooling water availability) than fossil plants.

[74] S&P finds that "Exposure to outages and their attendant costs is often exacerbated because nuclear outages tend to be lengthy relative to outages at other types of generation units given the complexity of nuclear reactors and the safety and regulatory issues that must be addressed before a nuclear unit is returned to service." S&P, *S&P Seeks Improved Risk - Assessment Metrics for U.S. Nuclear Power*, December 20, 2005.

While estimated unit availability and production are based on estimates that include past unit history and an understanding of the condition of the assets, the higher the capacity factor that is built into the forecasts, and the payments, the more asymmetry there is in the risk of exceeding versus falling short of forecast availability.

OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities. Every one TWh shortfall in production at a variable payment of $40 per MWh, which approximates the average variable portion of OPG's proposed nuclear payment amounts in Exhibit K1, Tab 3, Schedule 1, is equal to an approximately $40 million reduction in revenues. Since approximately 5.0% of the costs of nuclear production are variable, i.e., fuel costs (as per OPG's Exhibit I1-2-1), a $40 million reduction in revenues would reduce earnings from nuclear generation by approximately $25 million,[75] equivalent to a reduction in return on equity of approximately 0.6 percentage points relative to the total deemed equity ($4200 million) for the prescribed assets for 2008. To put this in perspective, in 2006, actual nuclear production fell 2.5 TWh below forecast. A 2.5 TWh production shortfall translates into a reduction in ROE of approximately 1.5 percentage points. It is important to note that the reduction in ROE would be higher if the proposed change in payment structure is not approved.

OPG's nuclear facilities are subject to the oversight of the Canadian Nuclear Safety Commission (CNSC), whose mandate is to protect the health and safety of persons and the environment, and to ensure national security from risks associated with the use of nuclear energy and nuclear material. The CNSC is responsible for licensing nuclear facilities during each of five phases in a nuclear plant's life cycle, site preparation, construction, operation, decommissioning and abandonment. In fulfilling its mandate, the CNSC has the ability to impose conditions of licenses, including, among other things, increased security requirements – which have become

[75] Equal to a reduction in revenue of $40 million less $2.0 million in variable costs, equivalent to $25 million in after-tax earnings at a 34% tax rate.

significantly more stringent since 9/11 – as well as increased safety and health standards.[76] Compliance with all security and health and safety regulations as well as license conditions is required in order for the nuclear facilities to continue to operate. OPG may incur significant operating and capital costs (as well as face curtailment of production and potentially permanent shutdown) to comply with such CNSC regulations and license conditions. Regarding environmental requirements, particularly with respect to discharges to the environment, and handling, use, storage, disposal and clean-up of hazardous substances, as well as the decommissioning of nuclear stations at the end of their useful lives, OPG also faces significant operating and capital costs. To the extent that nuclear production is adversely impacted by changes in legislation or regulations related to CNSC compliance or compliance with any other applicable laws, OPG is at risk, with the proviso that it retains the right to request a deferral account to recover related costs if they result in a material financial impact.[77]

Changing demographics, specifically an aging workforce, also create cost and production risks for all the regulated operations, but this issue is particularly pronounced for nuclear operations. Both availability and cost of nuclear-skilled employees are a concern, as the retirement of a large percentage of the skilled workforce becomes increasingly imminent. Bruce Power competes for available skilled personnel; training cycles are lengthy and costly. Similar to other employers, over 25% of OPG's workforce is eligible for retirement within the next 10 years.[78]

While the variable costs of nuclear production are not as significant as those of fossil generation, they are not immaterial. Market prices for uranium increased almost 200% over the period 2004-2006 due to a shortage in worldwide mine production and a drawdown of inventory. Speculation in uranium markets that as many as 168 nuclear plants could be built globally by 2020[79] drove the price from under $20 per pound in 2004 to over $70 per pound at the end of 2006. Since the

[76] Since 9/11, the threat of terrorism has emerged as an important risk factor for nuclear generation facilities.
[77] The proposal to seek a deferral account if related costs result in a material financial impact takes the place of the deferral account for unforeseen changes in technology or regulatory requirements established by Regulation 53/05.
[78] Statistics indicate that less than 45% of all nuclear engineers in the U.S. employed in 2004 would still be working in 2008.
[79] Melbye, Scott (Cameco), *Presentation to the World Nuclear Association Annual Symposium*, 2006.

beginning of 2007, market prices have continued to show high volatility with world prices reaching as high as $136 per pound (U.S.) from a low of $75 per pound (U.S.). Delays in bringing on new production could lead to even higher market prices. In addition, OPG's exposure to market prices for future years has increased due to a larger proportion of supply contracts that contain pricing indexed to market indicators at the time of delivery, a growing trend in the industry and a function of a strong sellers' market. For example, over 50% of the deliveries in 2009 are priced based on world prices at the time of delivery. Historically, a significant proportion of supply contracts were base price contracts with CPI or similar forms of escalation. This had resulted in considerably lower uncertainty in forecasting fuel expense than will be the case for the next several years. Higher uranium prices have already increased OPG forecast fuel expense in 2009 by almost 140% relative to 2004; continued increases in uranium prices could push the fuel expense even higher. As a result, regulated payments may not cover unanticipated uranium price increases. Given the significant volatility in uranium prices, which is not predictable and beyond management control, OPG is requesting a variance account to record variances between forecast and actual uranium costs. The proposed variance account would cover the preponderance of OPG's fuel price risk.

With respect to decommissioning and used fuel risks, OPG is responsible for the decommissioning of its nuclear stations, including the leased Bruce facilities[80], and for the management and disposal of used fuel from those plants. The Ontario Nuclear Funds Agreement (ONFA) between the Government of Ontario and OPG provides for segregated Decommissioning and Used Fuel Funds, and requires contributions to those funds, limits OPG's risk with respect to long-term used fuel management, and requires the Province to provide financial guarantees to CNSC that there will be funds available to discharge the used fuel and decommissioning liabilities.[81] Pursuant to ONFA, OPG's liability with respect to the management and disposal of used fuel is limited to approximately $6 billion based on the present value of the obligation in 1999 (approximately $9.1 billion in 2007 dollars). The Province and

[80] Bruce Power makes payments to OPG that cover decommissioning and waste management funding.
[81] The Provincial guarantee on unfunded liabilities was required by the CNSC to satisfy licensing requirements.

OPG have agreed to share cost increases associated with high level nuclear waste disposal up to a maximum of 2.23 million fuel bundles. In light of plans to refurbish and extend the lives of existing nuclear plants (including the refurbishment of Bruce A), current projections of high level nuclear waste now exceed 2.23 million fuel bundles. OPG assumes the liability for the additional waste and the related cost recovery risk. In contrast, the liability for used fuel in the U.S. is the responsibility of the Department of Energy; utilities with nuclear facilities pay a per kWh charge based on production to the government for assuming the disposal obligation. OPG bears the risk and liability for decommissioning cost estimate increases and fund earnings. At the end of 2006, based on the 2006 Reference Plan[82] for decommissioning, the Decommissioning Fund was fully funded. The rate of return on the Used Fuel Fund is guaranteed by the provincial government. At the end of 2006, the unfunded liability related to used fuel was approximately $2.4 billion.

While the decommissioning and used fuel liabilities are mitigated by funding them over time, the estimates are subject to change (e.g., changes in life cycle costs) each time the Reference Plan is revised (as required by legislation or every five years, whichever is earlier, or when there is a material change). A significant increase in the estimate of the liability could have a significant negative impact on OPG's financial condition. With respect to waste storage, although an options study for the disposal of high level waste has been submitted to the federal government, the choice of alternative could have a significant impact on the estimated liability. Risks associated with nuclear waste storage include financial impacts of sitting the geological repository and concerns in communities of interest. Licensing of the repository requires community support, which could deteriorate and result in protracted and costly processes. Similar issues exist with respect to the storage of low and intermediate level waste. The government has recently elevated the environmental assessment of OPG's proposed deep geological depository within the Bruce Nuclear site to a panel, which could result in material schedule delays and costs.

[82] The Reference Plan details the estimated costs of, and manner in which, the liabilities are to be discharged. ONFA requires periodic re-estimation of the decommissioning and used fuel obligations. The 2006 Reference plan raised OPG's liability by approximately $1.4 billion.

While Regulation 53/05 mitigates the risks to OPG as it requires that the OEB ensure that OPG recovers its costs related to ONFA, increased cash requirements for funding or a reduction in the time period over which those costs must be recovered could result in material pressures on the regulated payments.

Further, as time passes, the obligations to discharge the liabilities increase as the period over which the liability has been discounted to present value grows shorter. The potential ultimate result is that the size of the liability will eventually surpass the liabilities/net worth associated with OPG's actual operations. As regulated facilities are decommissioned, there is increasingly less production over which to recover future changes in the liabilities. The larger the liability relative to the actual operations of OPG, the greater is the impact of the volatility in the returns of the decommissioning fund on the overall volatility of OPG's earnings. Extension of the life of the nuclear facilities through refurbishment shifts the liability to a later time period, reducing the present value of the decommissioning liability. However, life extension also increases liabilities related to used fuel and waste management costs. In addition, since the assumption underlying decommissioning is that the reactors will be in safe storage for 30 years after the end of their useful life, and that dismantlement will take a further 10 years, there is a significant risk that the costs to service the liability will have changed, the decommissioning funds will not perform as was expected, and if they do not, that there will be no viable means to recover the deficit through regulated operations.

OPG is proposing to discontinue the variance account established under Regulation 53/05 for changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes. As of the end of December 2006, OPG had recorded no costs in this variance account. However, the relevant costs – which I interpret as exceptional events or discoveries that are outside of past experience – could be significant. To the extent that unanticipated costs are incurred due to unforeseen technological changes, OPG retains the ability to seek deferral of those costs for future recovery. Nevertheless, even if OPG seeks a deferral account in future, there is no guarantee that OPG will be allowed to recover 100% of the incurred costs.

B.4.c. Regulatory Risks

Chapter IV.B.2.c. discusses the regulatory environment as it impacts the composite regulated operations of OPG, including the nuclear operations. The key elements of the regulatory framework as they relate specifically to nuclear operations are discussed below.

Regulation 53/05 established several deferral and variance accounts for the nuclear operations. These included deferral and variance accounts for:

(1) non-capital costs associated with the return to service of Pickering A nuclear generating station units (PARTS Deferral Account);
(2) costs incurred prior to the Board's first rate order to refurbish, increase or add generation capacity or to develop new nuclear capacity (Increased Capacity/Output and Refurbishment Deferral Account);
(3) transmission outages and restrictions; and
(4) ONFA related costs (Nuclear Liabilities Deferral Account); and
(5) unforeseen changes in nuclear technology or regulatory requirements.

OPG is proposing to recover amounts accumulated in the PARTS deferral account over a period of 15 years; the only additional costs that will be added to this account are carrying costs. The costs accumulated in the Increased Capacity/Output and Refurbishment Deferral and the Nuclear Liabilites Deferral Accounts as of December 31, 2007 are forecast to be recovered in regulated payments by the end of 2010. As indicated above, OPG is proposing to eliminate the variance accounts for transmission outages and restrictions, Acts of God and unforeseen changes in nuclear technology or regulatory requirements (with the proviso that OPG may apply for accounts in the future should the related costs result in a material financial impact).

OPG faces significant capital expenditures for refurbishment of existing or to build new regulated nuclear facilities.[83] The undertaking of the refurbishment of existing nuclear unit or construction of a new nuclear plant would raise the risks to which the utility is exposed. With respect to new nuclear plant construction, S&P is of the view that, despite the recent excellent performance of nuclear plants, historic risks will persist throughout a new plant's life cycle. These risks include cost growth, design and scope changes, permitting delays, public opposition, regulatory changes, latent technical defects, and uncertain decommissioning costs. All else being equal, S&P has concluded, an electric utility with nuclear exposure has weaker credit than one without.[84]

The requirement to refurbish existing nuclear plants, or build new nuclear generation facilities would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures related to a fundamentally risky nuclear generation plant would help mitigate the increase in risks. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build.

B.5. Relative Business Risks of OPG's Regulated Operations

With respect to relative business risk, OPG's regulated operations face significantly higher business risks than the typical Canadian utility and the typical vertically integrated electric utility in Canada or the U.S., for the following reasons:

a. As a generation-only business, OPG's regulated operations have no low risk monopoly "wires" or distribution "pipes" operations. Generation is inherently subject to higher

[83] S&P has indicated that the "sheer amount of capital necessary to bring a new [nuclear] plant on line is daunting." S&P, *U.S. Is Looking at a Paced Reemergence of the Nuclear Power Option*, June 26, 2006.
[84] S&P, *Time for a New Start for U.S. Nuclear Energy?*, June 4, 2003.

market/competitive risks than “wires” or distribution “pipes”, for which the probability of duplication of facilities is virtually nil. Generation is also subject to higher operating and production risks than “wires” or “pipes” operations.

b. The existing nuclear plants are subject to significantly higher production/operating risks than other types of generation.

c. While the risk-sharing of used fuel obligations with the government caps OPG’s nuclear liability and the Nuclear Liabilites Deferral Account for ONFA costs mitigates the risks related to the nuclear liabilities, the long-run risks remain higher for OPG than for utilities with either no nuclear exposure, exposure tempered by the smaller size of nuclear operations relative to total operations, or where the government assumes the risk for a fee (as is the case in the U.S. for used fuel).

d. Regulatory risks are relatively high; there remains a risk of further political intervention that could alter OPG’s ability to recover a reasonable return on (or return of) the invested capital; and

e. Potentially high levels of capital expenditures for refurbishment and new plant construction expose OPG to significant cost recovery risks.

C. IMPORTANCE OF INVESTMENT GRADE DEBT RATINGS

In contrast to unregulated companies, public utilities have obligations that require them to raise capital “on demand”. Although OPG’s regulated operations are not governed by the traditional obligation to serve, its mandate includes continuous improvement of its nuclear generation fleet, including refurbishment of older units, and expansion, development and improvement of its hydroelectric generating capacity. In August 2007, the Ontario Power Authority (OPA) delivered to the Ontario Ministry of Energy its proposed 20-year plan for the Province’s electricity system. The plan outlined by OPA (subject to government approval) has been estimated to cost approximately $60 billion. In response to the OPA's initial recommendations (December 2005's *Supply Mix Advice and Recommendation Report*), OPG was directed by the government to begin an assessment of the refurbishment of existing nuclear units and the construction of new units. The success and cost of implementing the plan will depend in part on the ability of OPG and other generators to raise funds when required and on reasonable terms and conditions. If OPG is to be able to achieve a sustainable financial model as envisioned under the Memorandum of Agreement between OPG and the Province of Ontario, it needs to be able to access funds from the public markets for refurbishment and expansion.

In my opinion, to ensure access to the public markets, the capital structure for OPG's regulated operations should be sufficient to achieve debt ratings on a stand-alone basis in the A category. While debt ratings of BBB- or better are considered investment grade, debt ratings in the A category provide assurance that a utility will be able to access the debt markets as required on reasonable terms and conditions over the full interest rate or business cycle. If OPG is directed to refurbish or build new generating facilities, it will not have the flexibility to defer financing that an unregulated firm has.

Generation assets are long-lived. The life span of a nuclear generation facility is expected to be approximately 40 years; hydroelectric generation facilities can operate for periods in excess of 100 years. With long-lived assets, OPG needs to be able to access the long-term debt markets consistently. Financing long-term assets with short-term debt creates a mismatch between recovery of the investment in regulated payments and the return to investors of the capital committed, and exposes the utility to higher refinancing risk. Debt ratings in the A category will provide better assurance of predictable access to the long-term debt markets on reasonable terms and conditions than would BBB ratings.

Utilities with ratings in the BBB category not only will have to pay more for debt than A rated utilities, but they may have more onerous conditions attached to debt issues. In recent years, the spread between long-term BBB rated utility debt and A rated utility debt in Canada has been as high as 175 basis points.[85] In the U.S. over the past five years, the spread between A and Baa long-term utility bonds has been as high as 85 basis points. Of particular concern would be that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market.[86]

A utility with split ratings (that is, one debt rating agency rates the company's debt in the A category and another debt rating agency rates it in the BBB category) could face a materially higher cost of debt than a utility with both ratings in the A category. Debt investors are likely to take the lowest rating into account when pricing an issue. To illustrate, the credit spreads for new 30-year bond issues for Canadian utilities with split ratings have been approximately 35 basis points higher than for Canadian utilities for which all debt ratings are in the A category. Within the past five years, the spread differentials have been as high as approximately 65 basis points.

The public market for BBB rated debt remains more limited in Canada than in the U.S. Many institutions, who are major purchasers of corporate debt issues, either may not purchase BBB rated debt or have limitations on the proportion of BBB rated debt that they can hold in their portfolio. If an issuer's debt is downgraded further, into a non-investment grade category, the institution may have to dispose of its holdings in those securities. To illustrate, the NEB reported in its August 2005 *Canadian Hydrocarbon Transportation System Report* that Canadian bonds are an important revenue source to pension funds and other institutional investors, and a downgrade could require institutional holders to sell a large percentage of their bonds at discounted prices.[87]

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[85] Based on a comparison between the indicated spreads for TransAlta Corporation and Canadian utilities whose debt ratings are all in the A category.

[86] FortisBC, for example, rated at the time Baa3 by Moody's and BBB(high) by DBRS, had a difficult time during late 2004 and early 2005 accessing the 30-year debt market, despite the fact that the debt markets at the time were some of the most robust that had been experienced in Canada for years.

[87] More generally, the pension funds had indicated to the NEB that the basic financial parameters (allowed return on equity and deemed capital structure) in the Board's regulatory scheme should be improved.

D. DEBT RATINGS OF OPG

Ontario Power Generation Inc. is the entity that raises debt on behalf of the regulated operations and whose debt is rated. In 2006, the regulated operations of OPG accounted for approximately 60% of the company's total revenues and total generation. Thus, the views of the debt rating agencies with respect to OPG may provide some useful information regarding an appropriate stand-alone capital structure for the regulated operations.

D.1. DBRS

DBRS, which rates OPG's unsecured debt as A(low)[88], considers the key strengths of OPG as they relate to regulated operations to be:

a) Shareholder support;
b) Dominant market position;
c) More favourable interim regulatory framework relative to previous framework;
d) Nuclear waste management liabilities limited due to agreement with the Province.

The challenges related to regulated operations, in DBRS' view include:

a) Interim regulatory framework less favourable than in other North American jurisdictions;
b) Higher operating and financial risks associated with nuclear generation equipment;
c) Political intervention;
d) Significant capital program anticipated.

The sole challenge listed by DBRS that is unique to the unregulated operations is fuel cost risk associated with coal generation. Thus, it would be reasonable to conclude that DBRS views the

[88] DBRS, *Rating Report Ontario Power Generation Inc.*, August 3, 2006.

regulated operations as facing no less business risk than the unregulated operations. As such, DBRS' evaluation of the consolidated financial metrics and its resulting debt rating decision can be viewed as applicable to the regulated operations on a stand-alone basis.

DBRS notes that while OPG's cash flow-to-debt and interest coverage ratios have improved significantly and are strong relative to peers' (cash flow-to-debt ratio of 21.1% and fixed charge coverage of 4.55X in 2005, compared to 7.7% and 0.7X in 2004), the debt rating is limited by uncertainties with respect to closure of coal generation facilities, nuclear refurbishment, new nuclear build and the direction of regulation beyond 2008. The rating agency also referred to the fact that "OPG's regulated rates are based on an ROE of 5%, which is low in comparison to what the majority of other regulated generation companies receive in other jurisdictions in North America", and is lower than the ROEs of regulated transmission and distribution in Ontario, both of which have a lower business risk profile than generation. DBRS commented that regulated vertically integrated utilities in the U.S. have deemed capital structures ranging from 35% common equity to 55% common equity and have an approved ROE ranging from 9.75% to 13.5%. According to DBRS, a comparable entity to OPG (that is, one without stable transmission and distribution operations), according to DBRS, would be near the top of both ranges. DBRS concluded that if long-term certainty develops with respect to uncertainties related to local plant closures, nuclear refurbishment and new build, regulation beyond 2008, the level of allowed returns, and if financial ratios remain strong, it may consider a positive rating action.

The A(low) rating currently accorded OPG's consolidated operations, and which, as noted in IV.A.1, as of August 2006, was more "reflective of OPG's improved financial profile on a stand-alone basis" reflects a 2005 common equity ratio of close to 60%, a return on equity of 11.7% and the coverage ratios cited above.

D.2. Standard & Poor's

As noted above, Standard & Poor's rating for OPG of BBB+ reflects a two notch enhancement due to its relationship with its shareholder, the Province of Ontario. S&P views OPG's principal credit strengths as: [89]

a. Government ownership and implied financial support;
b. Fixed price for output from baseload nuclear and hydroelectric assets;
c. Diversified portfolio of generating assets; and
d. Strong cost-competitive position in its primary market.

Partially offsetting the credit strengths are:

a. Operational and technology risk associated with nuclear assets;
b. Non-regulated cash flow constraints related to unregulated operations due to a government-imposed revenue cap;
c. Volume risks on unregulated assets; and
d. An intermediate financial profile.

S&P's assessment of OPG's credit strengths and weaknesses suggests that it views the regulated operations as facing no less business risk than the unregulated operations, given its focus on the operational and technology risk of the nuclear facilities. Consequently, the recent consolidated financial parameters should be viewed as reflective of the level consistent with a stand-alone rating for the regulated operations in the BBB category.

[89] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.

S&P reported a 2006 debt/capital ratio of 55.6% versus 63.9% in 2005[90], reflecting its 2006 adoption in Canada of a measurement methodology that makes analytical adjustments to amounts reported in companies' financial statements and treats items such as unfunded OPEBs, pension fund deficits and operating leases as debt for purposes of calculating capital structure ratios.[91] The 2006 and 2005 Adjusted Funds from Operations Interest Coverage ratios were 3.7X and 4.9X respectively; the corresponding Adjusted Funds from Operations to Total Debt ratios were 10.6% and 14%.[92] S&P's expectation is that the financial profile will remain relatively stable in 2007 absent any material changes to financial policies or capital structure. S&P maintains a positive outlook on the rating, indicating that it:

> reflects an improved pricing framework and regulatory environment. The rating will likely move a notch higher if OPG can manage its expenses and operational performance within the bounds of its current license agreement and maintain its satisfactory financial profile in 2007 with a similar outlook for 2008 and beyond. For the rating to move a notch higher, there will also have to be an expectation of continued relative stability in both Ontario's electricity policy and regulatory framework and a clear financial policy for the company. The outlook could be revised to stable or negative as a result of a sustained period of significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities, or higher operating expense due to poor hydrology and higher prices for coal, with no related increase to the revenue cap. As the shareholder relationship evolves in the long term, there could be a change to the degree of support factored into the rating.

Based on both debt rating agency reports, the current debt ratings for the consolidated operations of OPG are based on common equity ratios, as measured by external debt and equity, in the range of 55-60%. To achieve and maintain similar stand-alone investment grade debt ratings, the deemed common equity ratio for the regulated operations would need to be in a similar range.

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[90] Standard & Poor's, *CreditStats: Electric Utilities – Canada*, September 10, 2007. Based on the methodology used by S&P prior to adopting analytic adjustments for these items, the 2005 debt ratio, based solely on debt and equity, would have been reported by S&P as 44%.

[91] In its December 2005 report for OPG, S&P reported the 2004 debt/capital ratio at 42.7% based on reported amounts of debt and equity; in the September 2006 and 2007 *CreditStats*, with S&P's analytic adjustments, it was reported to be 56.5%.

[92] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.

E. FINANCIAL METRIC GUIDELINES[93]

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), Standard & Poor's has published the most detailed matrix of quantitative guidelines for different debt ratings.[94] S&P assigns to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest. For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds from Operations Interest Coverage, and Funds from Operations To Total Debt. While the guidelines are not applied mechanically, they do represent one objective basis for evaluating an appropriate stand-alone capital structure for OPG's regulated operations.

The key qualitative factors that S&P evaluates in arriving at a business risk score for regulated companies, including generation, distribution, transmission and vertically integrated companies, include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness. Vertically integrated utilities generally have business profile scores of "5"-"6"[95]; generating companies have scores in the "7"-"10" range, with the level dependent upon the extent of the regulatory umbrella.[96] The analysis of the vertically integrated utilities as it regards operations is focused on the generation facilities. Specifically,

> [t]he status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant

[93] See Appendix H for complete quantitative guidelines.
[94] DBRS has published guidelines that do not distinguish by either business risk or investment-grade rating category.
[95] Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 14, 2006.
[96] Standard & Poor's, *Rating Methodology for Global Power Utilities*, August 30, 1999

additions necessary to provide high-quality, reliable service. The generation condition of the assets and how well such assets are maintained are also important.[97]

Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results.[98]

The average business profile score for Canadian utilities has been "3"; the majority of these are largely "wires" or "pipes" companies whose business risks are not comparable to those of OPG's regulated operations. Among the Canadian companies that have been assigned business profile scores is one vertically-integrated utility, Nova Scotia Power, which was assigned a score of "4" and TransAlta Corporation, assigned a "6". OPG's regulated operations, as solely generation, are riskier than Nova Scotia Power, whose operations include lower risk wires operations and no nuclear generation. In comparison to TransAlta Corporation, some of whose generating assets are subject to cost-of-service type Power Purchase Arrangements (approximately 45% of operating income) and none of which are nuclear, OPG's regulated operations would face no less business risk. On balance, it is likely that OPG's regulated operations would, on a stand-alone basis, be assigned a business profile score of "6".

S&P's guidelines for an A debt rating and a business risk score of "6" are as follows:

Table 6

Total Debt/Total Capital (%)	40-48
FFO Interest Coverage (x)	4.2-5.2
FFO/Average Total Debt (%)	28-35

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

[97] Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 14, 2006, p. 4.
[98] *Ibid.*, p. 4.

The guidelines for business risk profile scores of "6" indicate that a common equity ratio in the range of 52% to 60% is warranted for an A rating.

Moody's also has published quantitative guidelines. While OPG does not currently have a Moody's rating, there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's, including Hydro One. Thus Moody's guidelines are applicable to those companies and will play a role in the establishment of capital structures that will be adequate to maintain investment grade debt ratings. OPG's financial parameters will be compared against its peers', whose financial parameters will be judged against Moody's guidelines. Moody's guidelines for an A rating for a regulated company of "medium risk" are:

Table 7

FFO Interest Coverage (x)	3.5-6.0
FFO/Debt (%)	22-30
Retained Cash Flow/Debt (%)	13-25
Debt/Capital (%)	40-60

With only generation operations, of which close to half (as measured by assets) are nuclear generation, OPG's regulated operations would likely be viewed, on a stand-alone basis[99], as falling in the upper end of the risk spectrum, thus warranting a debt ratio in the lower end of the range for "medium risk" utilities. Hence, based on Moody's guidelines, a reasonable deemed

[99] Moody's actual ratings for publicly-owned utilities, in contrast to the approach of DBRS and S&P, reflect a methodology specific to government-related issuers. Its ratings for Hydro One, for example, explicitly consider the high degree of dependency between Hydro One and the local economy, Hydro One's operating and financial proximity to the government, and the support of the province as sole shareholder. In the absence of the implied government support, Moody's rating for Hydro One would be two notches lower than its Aa3 rating, that is, on a stand-alone basis, it would be rated A. According to its December 2005 report, Moody's considers Hydro One to have a credit risk of "3" on a scale of "1" to "6". OPG's regulated operations would likely have a materially higher credit risk, and a lower rating based on Moody's government-related methodology than Hydro One. Consistent with the differences between the other rating agencies' ratings for Hydro One and OPG, given the relationships between OPG and the provincial government, the most likely Moody's rating for OPG would be A.

common equity ratio for OPG's regulated operations compatible with a stand-alone A rating would be in the range of 50-60%.

The common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Thus, for example, if a utility is able to achieve adequate ratios such as FFO Interest Coverage and FFO/Debt ratios despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of ROE, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's guideline range for the debt ratio is an important indicator of an appropriate capital structure for OPG's regulated operations, but other financial metrics need to be taken into account. An analysis of stand-alone "notional"[100] coverage ratios at the benchmark return on equity of 10.5% and a common equity ratio of 57.5%, in the absence of experiencing risks that cause the actual performance of the regulated operations to fall short of expected levels, the principal cash flow metrics (FFO interest coverage and FFO to total debt) for the regulated operations would be expected to be sufficient to achieve and maintain stand-alone debt ratings in the A category.

F. CAPITAL STRUCTURES OF PEERS

The actual capital structures of OPG's peers, which underpin those utilities' debt ratings, may also provide some insight into an appropriate stand-alone capital structure for an A rating. Since there are no other regulated generation companies in North America, the closest peers for OPG's regulated operations would be, in Canada, TransAlta Utilities and TransAlta Corporation, and in the U.S., electric utilities with S&P business profile scores of "6".

[100] The debt rating agencies do not calculate ratios for individual divisions of a company; they look at the ratios of the entity that raises capital. The notional ratios were estimated solely to test the impact of the combination of hypothetical capital structure and return on equity on the ability of the regulated operations to attract capital and maintain their creditworthiness on a stand-alone basis.

TransAlta Corporation is rated BBB by both DBRS and S&P. TransAlta Utilities, the subsidiary of TransAlta Corporation that holds the PPAs for the "heritage" Alberta generation, is rated A(low) by DBRS and BBB+ by S&P. The debt ratio for TransAlta Corporation, as measured by DBRS, has averaged 47.9% from 2003-2005; the corresponding debt ratio for TransAlta Utilities has averaged 52.3%. The average ratios as measured by S&P for 2004-2006 were 53.2% for TransAlta Corporation and 21.1% for TransAlta Utilities. The differences in the measurement of the debt ratios for TransAlta Utilities by the two debt rating agencies relates primarily to the treatment of preferred securities and preferred shares; DBRS treats TransAlta Utilities' inter-company preferred securities as 50% debt and the perpetual preferred shares as 30% debt, while S&P treats both the preferred securities and shares as equity.[101] The large proportion of TransAlta Utilities' capital structure that is made up of "hybrid" preferred securities makes it difficult to draw definitive conclusions regarding a reasonable deemed debt/common equity capital structure for OPG. Moreover, since the ratings of TransAlta Utilities are split (A(low) by DBRS and BBB+ by S&P) and the ratings of TransAlta Corporation are both in the BBB category, they provide some insight into what would be warranted for a BBB rating, but not for an A rating. For a BBB rating, the TransAlta capital structures are indicative of a common equity ratio (based solely on a debt/equity split) of approximately 50% for a generating company.

With respect to U.S. companies, there are no A rated electric utilities with business profile scores of "6". The following table summarizes the debt ratios and other corresponding financial metrics for the universe of electric utilities with rated debt.

[101] Over 50% of TransAlta Utilities' 2005 total capital, when defined as debt, preferred securities and common equity, was preferred securities.

Table 8

Group	S&P Business Profile	2005 Debt Ratio [1/] (%)	S&P Credit Stats						Average ROE 2003-2005 (%)
			2005 Debt Ratio (%)	Average 2003-2005					
				Debt Ratio (%)	EBIT Coverage (X)	FFO/Debt (%)	FFO Coverage (X)		
	(Medians)								
All A Rated	4	51.6	55.9	56.6	3.7	21.8	4.8		12.2
All BBB Rated	5	51.8	56.8	57.2	2.8	19.5	4.1		10.5
BBB Business Profile 1-4	4	55.6	57.6	55.9	2.7	18.7	3.7		11.1
BBB Business Profile 5	5	51.0	55.4	56.1	2.7	20.9	4.0		10.6
BBB Business Profile 6	6	51.2	57.3	59.0	2.7	18.7	4.2		10.5
BBB Business Profile 7	7	54.7	59.3	61.5	3.5	20.6	4.3		13.7
BBB Business Profile 7-10	8	49.0	56.0	56.6	3.5	20.9	4.1		12.4
ENTIRE SAMPLE	5	51.7	56.6	56.8	2.9	20.7	4.2		10.9

[1/] Sum of long-and short-term debt divided by sum of long- and short-term debt, common equity and preferred stock.
Source: Schedule 27.

The table indicates that the typical debt ratio is approximately 55% (45% equity ratio) irrespective of debt rating category. However, the earned returns on equity for the utilities, at those capital structures, have been approximately 11% for the industry as a whole, 12% for the A rated utilities and approximately 12% for the highest risk companies. The resulting FFO Coverage ratios have been approximately 5 times for the A rated utilities (which are of lower business risk than OPG), and 4.2 times for the BBB rated companies with a "6" business profile score. FFO/Debt ratios are approximately 22% for the low risk A rated utilities and approximately 20% for BBB rated utilities with a "6" business profile score. The results suggest that the industry average is an approximately 45% common equity ratio. However, the equity ratio cannot be considered independently of the ROEs that have been key to the achievement of the utilities' financial metrics. As indicated above, the achievement of the referenced coverage ratios was dependent on earned returns on equity in the 11-12% range. In deriving an appropriate common equity ratio for OPG at the proposed benchmark return on equity of 10.5%, which is premised on equating the total risks of OPG's regulated operations to those of low business risk utilities rated in the A category, the deemed equity ratio will need to be higher than the industry average of 45%. The alternative is to set the capital structure at the industry standard, and to recognize OPG's higher business risks relative to the benchmark in the common equity return. Chapter IV.G following analyzes the trade-off between the equity ratio and the return on equity.

G. CAPITAL STRUCTURE FOR OPG AT BENCHMARK RETURN[102]

In contrast to OPG's regulated operations, which are 100% generation, the individual utilities used to derive the benchmark return on equity are largely "wires" or "pipes" companies. Of the seven individual Canadian utilities with publicly-traded stock[103], and for which betas were calculated, only three (Canadian Utilities, Emera and TransCanada) have any material generation activities. Of these three, only one has any nuclear generation; TransCanada has a 47.9% ownership stake in Bruce Power. The U.S. companies used to derive the benchmark return are also largely low risk wires and pipes utilities. Of the 13 utilities in the benchmark U.S. utility sample, only 5 are integrated electric utilities. The sample's asset mix includes approximately 2.5% generation based on the median and 15.0% generation based on the average. The average business profile score of the U.S. benchmark sample is "3", compared to the typical generation business profile score of "7" to "10". The business profile scores that have been assigned to Canadian utilities by S&P have averaged "3"; only two electricity firms, Emera/NSPI ("4") and TransAlta Corporation ("6") have been assigned scores higher than "3".

OPG's regulated operations, 100% of which are generation, and approximately 45% of whose regulated assets (65% of regulated generation capacity) are nuclear generation, are of significantly higher risk than the utilities used to establish the benchmark return. As discussed in Chapter III.A, the benchmark return is applicable to a typical, or average risk, Canadian utility. For the benchmark return to be applicable to OPG's regulated operations, the deemed capital structure must be estimated that would equate OPG's total (business plus financial) risks to those

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[102] A complete discussion of the methodology applied in this section is provided in Appendix I.
[103] The seven utilities referenced are: Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas, Terasen Inc. (stock has not been publicly-traded since its purchase by Kinder Morgan in November 2005), and TransCanada PipeLines.

of the utilities used to derive the benchmark return. The benchmark return would be applicable to a utility which, given its business risk and capital structure, would be able to achieve debt ratings in the A category.

In order to estimate the common equity ratio for OPG that would permit the application of the benchmark return to its regulated operations, I selected a sample of vertically integrated utility companies with significant generation operations in order to estimate the incremental cost of equity for regulated generation company like OPG. The incremental cost of equity for the "high generation" sample can then be translated into the common equity differential required to equate OPG's total business and financial risk to that of an average risk benchmark Canadian utility. At the identified common equity ratio, the benchmark utility return on equity will be applicable to OPG. For purposes of establishing the incremental cost of equity and the common equity differential, the sample of low risk U.S. electric and gas utilities (similar in risk to an average risk Canadian utility) served as the benchmark against which the selected sample of "high generation" U.S. utilities was compared.

The principal criteria for selection of the "high generation" sample included (1) an investment grade debt rating and (2) generation assets accounting for no less than one-third of total assets.[104] The selected sample includes 21 utilities with an average S&P debt rating of BBB (Moody's rating of Baa2), and an average proportion of generation to total assets of 48%. Sixteen of the 21 utilities have nuclear generation.[105]

The comparative S&P business profile scores, debt ratings, betas and common equity ratios of the high generation and benchmark low risk utility samples are provided in the table below.

[104] Criteria for selection of the "high generation" utilities are set out in Appendix I.
[105] The selected utilities are listed on Schedule 28.

Table 9

	***Value Line* Beta**	**Research Insight Beta**	**Average of *Value Line* and Research Insight Betas**	**S&P Business Profile**	**S&P Debt Rating**	**Moody's**	**Common Equity Ratio (2006)**
Benchmark Utility Sample							
Mean	0.86	0.59	0.73	3	A	A2	44.9%
Median	0.85	0.60	0.73	3	A	A3	44.6%
Weighted Average	0.80	0.53	0.67	4	A	A2	43.5%
High Generation Utility Sample							
Mean	0.93	0.77	0.85	6	BBB	Baa2	44.8%
Median	0.95	0.81	0.88	6	BBB	Baa2	45.8%
Weighted Average	0.93	0.68	0.81	6	BBB+	Baa1	43.0%

Source: Schedules 13 and 28.

The betas in the table are investment risk or levered betas. Investment risk betas are a function of both business and financial risks. When the financial risks of the sample companies (capital structures) are materially different, the business and financial risk components of the investment risk betas need to be segregated to determine how much of the risk differential between the samples is due to differences in business risk and how much is due to differences in financial risk. In the case of the high generation and benchmark utility samples, the capital structure ratios are very similar. Hence, the differences in the investment risk betas of the samples can be attributed to differences in business risk. The conclusion that the principal risk difference is related to business risk is supported by the difference in the S&P business risk profile scores between the two samples; "3" for the benchmark sample and "6" for the high generation sample.

Based on the average of the *Value Line* and Research Insight adjusted betas, the beta for the high generation sample is approximately 0.84 versus 0.71 for the benchmark sample. Using my estimated 6.5% market risk premium, the difference in equity return requirement between a high generation utility and the benchmark is close to 1.0 percentage point ((0.84-0.71) X 6.5%= 0.85%). As both samples have similar common equity ratios (approximately 45%), the approximately 1.0% differential in return requirement is applicable to a higher business risk utility at a 45% common equity ratio. Since the high generation sample contains significant wires operations (43.7% of assets on average), this differential equity return requirement should be viewed as the minimum difference required for a generation-only company with a common equity ratio of 45%.

The high generation sample was then used to derive a generation-only beta using the residual beta model (See Appendix I for theoretical basis). The residual beta model is based on the premise that the beta for the company is a weighted average of the betas of the individual betas of the different divisions of the company. If the beta for the company is known, and the betas for all but one of the divisions can be separately estimated, the beta for the remaining division can be derived by disaggregating the beta for the company as a whole. The residual generation-only beta was estimated using the following equation:

$$\beta_{HighGx} = \beta_{Gx} \text{ x } \%Assets_{Gx} + \beta_{Pure\ Wires} \text{ x } \%Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

The beta for the “wires” operations of the high generation sample was estimated from a sample of utilities with primarily “wires” operations. The selection of the “wires” sample is described in Appendix I. The beta of pure wires was estimated at 0.70; the beta for the “other operations” which account for 8.0% of the assets of the high generation sample was assumed to be 1.0, equal to the beta for the market as a whole (or, alternatively, of an average risk stock). The common equity ratio of the “wires” sample, at 43.7%, is virtually identical to the common equity ratio for the high generation sample. Thus, since the average common equity ratio of the “wires” sample is identical to that of the “high generation” sample, differences in beta between the two samples can be attributed to differences in business risk (i.e., there is no need to segregate the investment risk betas of the "wires" sample into business and financial risks components). Using the formula and betas above, the derived beta for generation-only was estimated at 0.94. The difference in the equity return requirement between generation and a benchmark utility can then be estimated as approximately 1.5%, calculated as the difference in betas multiplied times the market risk premium ((0.94-0.71) X 6.5% = 1.5%). As with the estimation of the return requirement differential based on the high generation sample compared to the benchmark sample, the 1.5% applies to a generation-only company with a similar common equity ratio, that is, 45%.

Because OPG's regulated operations are 100% generation, the incremental equity returns at a 45% equity ratio are at the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%. This incremental equity return was then used to develop the range of equity ratios for OPG's regulated operations that would be required to equate the fair return for OPG's regulated operations to the benchmark return of 10.5%. The quantification of the common equity ratio range was based on the application of two capital structure theories.

Theory 1 posits that income taxes and the deductibility of interest for corporate income tax purposes have no impact on the cost of capital. Under this theory, the overall cost of capital stays constant when the capital structure changes, although the costs of the debt and equity components change (i.e., the cost of equity rises when the equity ratio declines). Theory 2 posits that income taxes and the corporate deductibility of interest expense cause the overall cost of capital to continually decline as the equity ratio declines and the debt ratio increases. The actual impact on the cost of capital most likely lies in between the results of the two theories; income taxes and the deductibility of interest do tend to decrease the cost of capital (as the income trust market has demonstrated), but as the debt ratio rises, there are increasing costs in terms of loss of financing flexibility and potential bankruptcy. Moreover, in the case of regulated companies, the benefit of the tax deductibility of interest is to the benefit of ratepayers, while in the unregulated sector, the benefit goes to the shareholder. Since both theories have merit, both were applied to estimate the impact of a change in return on equity on capital structure.

The table below indicates that, based on both theories, the range of common equity ratios required to equate the return on equity for OPG's regulated operations to the benchmark return of 10.5% is in the range of 55-60%.

Table 10

	Common Equity Ratio		
	55%	**57.5%**	**60%**
Theory 1	10.5%	10.2%	10.0%
Theory 2	11.0%	10.8%	10.6%
Average	10.75%	10.5%	10.3%

Source: Appendix I and Schedule 31.

H. RECOMMENDED CAPITAL STRUCTURE AND FAIR RETURN

Based on (1) my analysis of the OPG's business risks, (2) the debt rating agencies' quantitative guidelines for specific debt ratings, (3) OPG's own debt ratings and its financial metrics, (4) the financial metrics of the electricity industry (including equity ratios), and (5) the incremental cost of equity for regulated generation relative to that of integrated utilities, the deemed common equity ratio for OPG's regulated operations should be set within a range of 55-60% (mid-point of 57.5%). A 57.5% common equity ratio would, in my opinion, be adequate to allow OPG's regulated operations to achieve a stand-alone debt rating in the A category. On the basis of the combined business and financial risks, OPG's regulated operations would then be of approximately equivalent total risk to a benchmark utility. At a 55-60% deemed common equity ratio, the fair return for OPG's regulated operations is equal to the benchmark return on equity of 10.5%.

I. IMPLIED CAPITAL STRUCTURE OF OPG'S UNREGULATED OPERATIONS

The objective of adherence to the stand-alone principle for purposes of determining the deemed capital structure and return on equity is to ensure that ratepayers are bearing a cost of capital that represents the risks of the regulated activities of the firm, not the risks of the consolidated operations. An element of the application of the stand-alone principle is ensuring that the regulated operations are not subsidizing unregulated operations. A cross-subsidy can be said to exist if the regulated operations are bearing costs that are the responsibility of the unregulated operations.

Since the proposed deemed common equity ratio for the regulated operations of 57.5% is lower than OPG's 2006 consolidated equity ratio as reflected in OPG's audited financial statements, assuming the consolidated equity ratios were maintained, the implied unregulated operations' common equity ratio is higher than the proposed deemed ratio for regulated operations. Further, the profitability of the consolidated operations and the individual business segments since the implementation of the Electric Restructuring Act 2004 indicate that the unregulated segment has been largely responsible for the improved financial position of OPG. As reported by DBRS, the return on equity for the consolidated operations was 11.7% in 2005 compared to the ROE of 5.0% on the prescribed assets. The unregulated operations, which account for approximately one-third of the assets, contributed over 50% of the operating income in both 2005 and 2006 as per OPG's audited financial statements.

Given that the unregulated operations – which are comprised largely of coal, oil/gas, hydro and wind generation – add to the diversification of OPG's overall portfolio of generation, contribute more than 50% of the operating income of the operations (even with a revenue cap in place), and have an implied common equity ratio slightly higher than that proposed for the regulated operations, there is no basis for any concern that, with a deemed common equity ratio of 57.5%, the regulated operations would be subsidizing the unregulated operations.

V. CAPITAL MARKET VIEWS ON FAIR RETURN/CAPITAL STRUCTURE

A. IMPLICATIONS OF GLOBALIZATION OF CAPITAL MARKETS

With the potential for refurbishment of existing nuclear units and construction of new nuclear units, OPG could be facing unprecedented capital expenditures for regulated generation over the next 20 years. As noted earlier, OPA has estimated that the plan to ensure the reliability of the Ontario's electricity supply could cost approximately $60 billion, of which approximately $26 billion could be for refurbishment of existing nuclear units and construction of new units.[106] OPG would not be alone in facing large capital expenditures. In its 2003 *World Energy Investment Outlook*, the International Energy Agency estimated that over $1.5 trillion in investment would be required by the electricity industry in North America. OPG will thus be competing for capital in a market that may be characterized by an unprecedented requirement for debt capital by a single industry. To compete successfully in the public debt markets, that is, to be able to attract capital on flexible terms and conditions, OPG will require financial metrics that are compatible with its peers on a risk-adjusted basis. Its peers are increasingly global, not solely Canadian.

Globalization of the capital markets has been a gradual phenomenon, as information barriers and transactions costs have declined, and financial reporting has become more standardized. The repeal of the Foreign Property Rule (FPR) in Canada in August 2005 has eliminated a further barrier, effectively releasing investment that was previously captive. Comparisons among companies across boundaries have become increasingly common. For example, S&P's peer

[106] The forecast costs for nuclear refurbishment and new build are not specific to OPG.

comparison for OPG includes two Canadian companies (TransAlta and Emera) and a U.S. company, Exelon.[107] With investors more willing to invest capital across international boundaries, a regulated company's ability to offer a return that is compensatory with its risk and comparable to its peers' becomes an increasingly imperative objective.

In the U.S., the average return on equity allowed for electric utilities by state regulators from the beginning of 2003 to the end of the second quarter of 2007, during which the long-term U.S. Treasury bond yield averaged 4.9% – virtually identical to the forecast 2008 5.0% long Canada yield – was 10.6% on a common equity ratio of 47.7%. The approved returns and capital structures are for both "wires" only (transmission/distribution companies) and vertically integrated companies, both of which would be less risky than OPG, whose regulated operations are generation-only. At the U.S. federal level, the Federal Energy Regulatory Commission (FERC) sets returns and capital structures for electricity transmission, for which the recent allowed "baseline" returns on equity have been in the range of 10.8%-12.4% on equity ratios in the 50-60% range. Baseline returns are exclusive of incentives. Since generation is riskier than transmission, the FERC returns would be supportive of returns in excess of 11-12%.[108]

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[107] TransAlta's peers are PPL Corp and Constellation Energy, both U.S. companies.

[108] The Conference Board of Canada has pointed out the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled, "*Electricity Restructuring: Opening Power Markets*", the Conference Board stated,

> 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. 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.

That conclusion would be no less true for regulated generation.

B. VIEWS OF CANADIAN DEBT RATING AGENCIES

As indicated in Chapter III.D, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a regulated company. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity component, but also the return allowed on that equity component and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S.

DBRS has noted that it would like to see both the deemed common equity ratios and allowed returns increased to levels more consistent with U.S. returns. [109]

In December 2004, subsequent to the AEUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity and returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

Additional recent DBRS reports citing the challenge of low approved returns on equity have been published for other Alberta utilities, i.e., AltaLink (November 2004), and FortisAlberta (September 2004).

As previously noted, IV.D.1, DBRS has commented with specific reference to OPG, that regulated vertically integrated utilities in the U.S. have deemed capital structures ranging from

[109] DBRS, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, May 2003.

35% common equity to 55% common equity and have an approved ROE ranging from 9.75% to 13.5%. A comparable entity to OPG (that is, one without stable transmission and distribution operations), according to DBRS, would be near the top of both ranges.

With respect to Standard & Poor's, in early March 2003, the debt rating agency announced that it was re-evaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation).

S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

For example, like DBRS, S&P has made references to the low level of equity ratios allowed in the EUB's Generic Cost of Capital decision for other Alberta utilities. Subsequent to the EUB decision, S&P commented on the thin equity layers allowed the ATCO group of utilities, stating,

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004.)

In a relatively recent report for AltaLink (rated A-), S&P stated,

> Like many regulated utilities in Canada, AltaLink's average financial profile is constrained by a comparatively low approved ROE (8.93% in 2006) on a thin deemed equity base of 35%. (S&P, *Research Summary: AltaLink*, June 5, 2006)

In its report for Union Gas issued subsequent to the utility's 2006 settlement in which the allowed common equity ratio was raised to 36%, the two weaknesses referred to by S&P were the high leverage associated with company's regulated capital structure and the relatively low allowed ROE compared with global peers (S&P, *Research: Union Gas*, August 24, 2006).

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[110] As noted above, the "aggressive leverage" is largely a result of regulatory directives.

C. VIEWS OF EQUITY ANALYSTS

Canadian equity analysts rarely comment on the level of allowed returns and capital structures of regulated companies. However, there have been some notable exceptions. As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

[110] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

In the NEB's August 2005 *Canadian Hydrocarbon Transportation System* report, as noted above, pension funds had indicated to the Board that the basic financial parameters (allowed return on equity and deemed capital structure) in its regulatory scheme should be improved. In its 2006 report of the same name, the NEB reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they have "Buy" recommendations on utility stocks, the recommendations tend to reflect the prospects of the unregulated operations.[111] Analysts also commented that companies have reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views. Some parties expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated that,

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

The most recent analyst commentary on the level of allowed ROEs in Canada expresses the view that the current level of allowed ROEs, expected to be approximately 8.6% in 2007, is now confiscatory. Specifically, in *Pipelines/Gas & Electric Utilities,* dated December 7, 2006, Karen Taylor, equity analyst for BMO Capital Markets, concluded:

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[111] In many cases, the ROEs achieved by the entity whose shares are traded have been materially higher than the ROEs allowed under the formulas. The allowed ROE generated by the NEB formula averaged 9.6% over the period 2002 to 2005; the ROE reported for TransCanada Pipelines Ltd by DBRS over that same period was 12.7%. For Terasen Gas, its allowed ROE averaged 9.2%; Terasen Inc.'s ROE (as reported by DBRS) averaged 11.1%. DBRS reported an average ROE of 13.0% for Canadian Utilities Ltd., compared to its regulated subsidiaries' allowed ROEs of approximately 9.6%.

We believe that regulators have consistently refused to give weight to a number of arguments that would result in higher allowed returns, solely on the basis that to do so would result in higher customer rates.

- The North American capital markets are increasingly integrated and investors have the ability to invest in utility assets north and south of the border.
- There is merit incorporating U.S. market metrics into the analysis and that the Canadian benchmark equity portfolio (the S&P/TSX) may not meet the theoretical requirement for a diversified market portfolio.
- The returns on comparable investments with similar risk, whether they be Canadian or U.S. examples, should be considered.
- The allowed return on equity and deemed equity must satisfy all aspects of the Fair Return Standard and that no part of the Standard has priority. ….
- No pipeline or energy utility in our regulated coverage universe has issued equity in the last five years to fund, on an unlevered basis, a dollar-for-dollar equity investment in utility rate base. Continued assertions by regulators that utilities have adequate access to capital are not credible with respect to the equity component, as access to equity has not been tested over the ensuing period. ….
- Continued investment in utility rate base by the owners of utilities is not an acquiescence that the allowed return on equity is appropriate and that investment may relate to other obligations including the utility's obligation to be the supplier or supply of last resort and fulfill the obligation to serve, maintain the safe and reliable operation of the utility, and may be fulfilling specific conditions of its operating licence. ….
- A failure by utility companies to annually litigate the allowed return on equity "formula" does not constitute acceptance of the adequacy of the allowed return. Rather, we believe that the lack of annual litigation reflects the cost of the process, the time required to pursue litigation that detracts from management's ability to focus on the efficient operation of the business and the potential damage to important utility regulatory and customer relationships. ….
- The evidenciary standard is too high and almost impossible to meet. Moreover, we believe that notwithstanding decisions from the Supreme Court that stipulate otherwise, utility regulators continue to rely heavily on their quasi-judicial and expert status to impose a bare-bones return on equity and drive down the deemed capital structure of the utility in order to protect customers from prices, without the fear of reconsideration upon appeal. Regulators must establish the cost of equity and deemed equity not because they are experts in this regard, but in order to establish just and reasonable rates. The regulator is not permitted to consider the effects

> on customers in the determination of the allowed ROE and capital structure, and we do not believe that the regulator is permitted to factor in other policy objectives into its determination of the allowed return on equity; i.e., we do not believe that the regulator is permitted to reduce the allowed return on equity and/or deemed equity for small utility companies in other to encourage consolidation or any other specific policy objective. We believe in these situations, that the inclusion of these other factors in the assessment of cost of equity and designation of deemed equity, unlawfully transfers value to utility ratepayers from its legitimate owner, the utility shareholders.

In sum, the returns available to comparable U.S. utilities are materially higher than the returns that are allowed to Canadian utilities, the returns allowed for Canadian utilities are generally regarded as too low, and the returns that investors expect and are achieving from the traded entities in Canada are considerably higher than the returns that have been allowed by regulators. These factors are legitimate considerations to be taken into account in setting a fair and reasonable return for OPG's regulated operations.

VI. AUTOMATIC ADJUSTMENT MECHANISM

The key purpose of automatic adjustment mechanisms for return on equity (ROE) is to avoid annual reviews of the allowed return on equity. The appropriate return on equity is unobservable (in contrast to the cost of debt) and is subject to a wide difference of opinion. Testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Considerable time, effort and money are spent on testimony preparation, information requests, and cross-examination. An automatic adjustment mechanism is a means of avoiding annual ROE reviews, while providing timely changes in the allowed return on equity. Since OPG is likely to face a number of limited issue hearings over the next several years, with ROE assigned to the first, the consideration of an automatic adjustment mechanism is particularly germane. The ROE can be set in the first proceeding, with no further need to address the issue throughout the remaining limited issues proceeding.

An automatic adjustment mechanism for ROE is relied upon in six different regulatory jurisdictions in Canada. The OEB first introduced an automatic adjustment mechanism in 1997 for the natural gas utilities; it approved automatic adjustment mechanisms for Hydro One and the electricity distributors in 1998 and 1999 respectively. The Board's automatic adjustment mechanism for the gas distributors was reviewed in detail in 2003 and reconfirmed in early 2004. In its *Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 20, 2006, the Board has retained the existing automatic adjustment mechanism for the electricity distributors as part of its guidelines for setting rates for 2007-2009.

The automatic adjustment mechanisms currently operating in Canada are all quite similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a "base" or initial ROE and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base ROE are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula to be used to adjust the ROE from one year to the next. The yield on the benchmark long-term (30-year) Government of Canada bond is used as the proxy for the risk-free rate.

The methodology used by the OEB has two components, the "initial setup" and the "adjustment mechanism". The "initial setup" has two steps: (1) establish the forecast of the long-term Canada yield for the test year and (2) establish the implied risk premium. The "adjustment mechanism" also has two steps: (1) establish the forecast long Canada rate and (2) apply the adjustment factor. The adjustment factor was specified in the Guidelines at 0.75. The adjustment factor of 0.75 means that the allowed ROE changes by 75% of the change in the forecast long-term Government of Canada bond yield. The same 75% adjustment mechanism is used by four of the other five regulators that rely on automatic adjustment mechanisms.

The key advantages of an automatic adjustment mechanism are as follows:

1. It reduces the regulatory burden imposed by the annual determination of ROEs.

2. It results in increased predictability of the allowed returns;

3. It avoids any potential arbitrariness of the outcome.

The principal disadvantages include:

1. There are constraints placed on the regulator's flexibility in setting the allowed return to address issues such as financing flexibility requirements;

2. If the base return is inadequate or excessive, the operation of the formula could potentially compound problems with the initial ROE;

3. If the formula adopted does not appropriately track changes in the cost of equity, subsequent allowed ROEs may not be representative of a fair return, and potentially, an impairment of financing flexibility.

4. There is a potential for more volatility in the regulated payments if the ROE changes materially from year-to-year than if the ROE remains unchanged for an extended period.

5. Some parties believe that the use of an automatic adjustment formula based on changes in the risk-free rate requires that the base ROE be determined solely on the basis of the equity risk premium test.

If there are sufficient safeguards in place that permit the formula to be revisited or that permit the utility to seek relief in circumstances of financial distress, the principal disadvantages of an automatic adjustment formula can be overcome. Moreover, financial flexibility concerns can be addressed through a change in the deemed capital structure. While DBRS has called the sensitivity of Canadian utilities' earnings to interest rates a "Challenge", the experienced year-to-year changes in formula-driven ROEs do not individually have a major negative impact on interest coverage. However, a steady decline in ROEs over a number of years will have (and has had) a cumulative impact, largely because the embedded cost of debt declines more slowly than allowed ROEs.

With respect to any concerns that the automatic adjustment mechanism sacrifices the contribution of tests other than the equity risk premium test, that concern is misplaced. The reliance on an interest rate to adjust the ROE from year to year, does not exclude, for purposes of setting the initial return, reliance on tests whose formulation does not include an interest rate. In this regard, I note that the BCUC and the AEUB, when setting the base return in their recent "generic" cost of capital decisions (2006 and 2004 respectively), looked at all of the tests and market information on their own merits, not whether they were based on the same parameters as the proposed automatic adjustment formula.

I recommend the adoption of an automatic adjustment formula for OPG, recognizing that a key to its success is the Board's adoption of a reasonable initial return.[112] With respect to the specifics of the adjustment mechanism, the Board's existing formula for subsequent changes in ROE, that is, a 75 basis point change in ROE for every one percentage point change in the forecast 30-year Canada bond yields, remains a reasonable approximation of the relationship between cost of equity and interest rates. However, OPG should retain the right to seek a review of the formula if there is evidence that the formula itself is not producing returns that will allow OPG to attract capital on reasonable terms (e.g., a threat of a downgrade to non-investment grade, assuming that threat can be tied, at least in part, to regulated operations).

As a further protection, I recommend that the formula should be reviewed if forecast long Canada bond yields fall below 3.0% or exceed 8.0%. Long Canada yields outside of the range of 3.0%-8.0% may indicate a materially altered relationship between long Canada bond yields and the utility cost of equity. The specification of 3.0% as the bottom end of the range recognizes there has been no experience with long-term Canada yields near this level since the early 1950s. With respect to the upper end of the range, if long Canada bond yields were to reach 8.0%, the real cost of capital or inflation would be materially higher than that which is currently anticipated. Both circumstances would warrant a review of the validity of the formula.

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[112] The importance of the internal consistency between the initial return and the automatic adjustment formula must be underscored. It would be unreasonable for the Board to allow a return on equity that implicitly assumes that the cost of equity has declined by 100% of the decline in interest rates since the persistent downward trend began in 1995, but then impose a formula that only increases the allowed return by 75% of future increases in interest rates.

APPENDICES
TO

Capital Structure and Fair Return on Equity

Prepared for

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APPENDICES

APPENDIX A

DEEMED VERSUS ACTUAL CAPITAL STRUCTURE

DEFINITION OF DEEMED CAPITAL STRUCTURE

The term deemed, or hypothetical, capital structure, simply refers to imputing, for ratemaking purposes, a capital structure that is different from the capital structure that is reported on the utility's financial statements or forecast to be reported on the financial statements during the test period. The most common method of applying the deemed capital structure construct is to:

1. estimate the rate base;

2. apply to the rate base a pre-determined percentage of common equity;

3. attribute to the regulated operations actual outstanding and forecast issues of long-term debt and preferred shares; and

4. to the extent that the rate base and the sum of the deemed common equity and the available actual long-term debt and equity do not match, balance the rate base and capital structure with a "plug", either debt (if rate base is greater than capitalization) or notional investments (if capitalization is greater than rate base).

HISTORY OF DEEMED CAPITAL STRUCTURE IN CANADA

Deemed capital structures have been used in Canada since at least 1978. The Ontario Energy Board has relied on deemed capital structures for the local gas distribution utilities it regulates since at least 1981.[113] The use of deemed capital structures arose in the context of applying what has been referred to as the stand-alone principle. Adherence to the stand-alone principle requires setting a capital structure and cost of capital that reflect the risks of the regulated utility as a stand-alone entity, not those of the legal entity within which the regulated utility resides.[114] The perceived need for reliance on deemed capital structures was primarily the result of the extent to which regulated companies were diversified into operations whose risks were significantly different from those of their regulated operations. The consolidated capital structure and cost of capital were thus viewed as not representative of the capital structures the regulated entity would maintain on a stand-alone basis or of the cost of capital the regulated entity would face on a stand-alone basis. The stand-alone capital structure and return on rate base were intended to

[113] In EBRO 376-I & II (January 30, 1981), the OEB approved a stand-alone capital structure for Consumers Gas (now Enbridge Gas Distribution).
[114] The Alberta Energy and Utilities Board (EUB) described the stand-alone principle as follows:

> This first application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. Using the stand-alone principle in this case, a utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged. This application of the principle ensures that the revenue requirement of regulated utility operations is not influenced up or down by the operations of a parent or 'sister' company. Thus the cost (or revenue requirement) of providing utility service reflects only the expenses, capital costs, risks and required returns associated with the provision of the regulated service. (emphasis added) (Decision 2001-92, December 12, 2001, pp. 24-25).

protect the ratepayers from the impacts of the consolidated companies' non-regulated operations.[115]

While the deemed capital structure construct was initially applied in situations where there were significant non-regulated operations co-mingled with the regulated operations (in the same corporate entity), it has become the standard Canadian approach, even in situations where the regulated entity is for all intents and purposes a "pure play" utility. This is the case for natural gas and electricity distribution utilities in Ontario. I am aware of no utility in Canada with significant non-regulated operations whose ratemaking capital structure is based on its actual capital structure.

In the North American context, the wide-spread use of a deemed capital structure is primarily a Canadian phenomenon.[116] Its use in the United States has generally been limited to circumstances in which the utility's actual common equity ratio is determined to be well above the level maintained by its peers.

RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND RETURN ON EQUITY

The basic principle that underpins the determination of the stand-alone cost of capital is that the opportunity cost of capital to a firm, or division of a firm, is a function of its business risks. The financing of the assets with a combination of debt and equity can lower the overall (weighted average) cost of capital, since debt is less expensive than equity, and interest expense is deductible for corporate income tax purposes. However, too much debt will increase the

[115] The stand-alone principle has also been applied to other types of costs, including income taxes and OM&A.
[116] The approach used to set the cost of capital for utilities in the UK is also based on a deemed capital structure.

weighted average cost of capital, as the costs of financial distress will outweigh the benefits of additional debt. Two other factors offset some of the advantage of using debt in the capital structure. The first factor is the impact of personal income taxes on interest income. While interest expense is deductible at the corporate level, the corresponding interest income is taxable to individual investors at higher rates than on equity income (dividends and capital gains). Second, in the case of regulated utilities, the benefits of the tax deductibility of interest expense flow to ratepayers, not shareholders, as the revenue requirement is reduced to reflect the lower corporate income tax expense.

In theory, there exists an optimal capital structure, i.e., one that minimizes the overall cost of capital. For tax-paying utilities, the ability to deduct interest expense for tax purposes creates a compelling incentive to pinpoint an optimal capital structure. However, it is not possible to pin-point the optimal capital structure. In practice, there exists a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably. Despite wide-spread agreement in the academic community (as well as among practitioners) that the optimal capital structure can not be precisely identified, the use of a deemed capital structure for ratemaking purpose is effectively based on the premise that it can be estimated within a relatively narrow range.

There is agreement, however, that as a general proposition, companies with less business risk can safely assume more debt than those with higher business risk without impairing their ability to access the capital markets on reasonable terms and conditions. In principle, higher business risk can be "offset" by maintaining or imputing a higher common equity ratio, so that two utilities with different levels of business risk and different capital structures would face similar costs of debt and equity.

ESTIMATING CAPITAL STRUCTURES AND RETURNS ON EQUITY: REGULATORY APPROACHES

There are effectively two approaches that have been used by Canadian regulators to determine the deemed capital structure and corresponding return on equity. The first has been to assess the "subject" utility's business risks, then establish a capital structure that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone investment grade debt rating; and (c) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of the proxy firms' cost of equity to the subject utility without any adjustment to the "benchmark" return on equity.

The second approach entails establishing a deemed capital structure that is reasonable, but does not necessarily equate its total risks to those of a "benchmark." Using the adopted equity ratio, the utility's level of total risk (business plus financial) is then compared against that faced by the proxy firms that were used to estimate the equity return requirement. If the total risk of the proxies is higher or lower than that of the subject utility, an adjustment (typically a premium) to their cost of equity is made when setting the subject utility's allowed return on equity.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the first approach as long as the combination of allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. Both of these approaches have been adopted by Canadian regulators.

The National Energy Board adopted the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in its 1995 Multi-Pipeline Cost of Capital Decision. Each individual pipeline was deemed a common equity ratio that was intended to compensate for its business risk relative to the other pipelines, so that a single "benchmark" return on equity could be applied across all of the pipelines. In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002 and 36% in 2005,[117] but the ROE has continued to be determined annually using the automatic adjustment mechanism adopted in 1995.

The same approach was adopted by the EUB in Decision 2004-052 (July 2, 2004). In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common "benchmark" return on equity to be applied to each of the utilities under its jurisdiction. The EUB's decision established allowed common equity ratios ranging from 33% for electric transmission to 43% for a relatively risky gas pipeline. In the middle of the business risk range were the major electricity and gas distributors with allowed common equity ratios of 37% and 38%, respectively.

In contrast to the NEB and EUB approach, the British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. In every year since 1994, the BCUC has determined a benchmark

[117] Deemed at 40% by Negotiated Settlement for 2007-2011, approved by the NEB in May 2007.

low risk utility return on equity using an automatic adjustment formula (which has been amended several times) and has designated Terasen Gas as the benchmark low risk utility. Each of the utilities regulated by the BCUC has its own unique deemed capital structure and allowed equity risk premium (expressed as a premium to the low risk benchmark utility equity risk premium). The company-specific capital structures and equity risk premiums (relative to the benchmark) can be reviewed during the individual utility's company-specific revenue requirement proceedings. Theoretically, the combination of capital structure and return on equity for each utility should reasonably compensate it for its business risk relative to that of its peers.

The Régie de l'Energie de Québec has also used a combination of deemed capital structures and returns on equity. The two gas utilities and the transmission and distribution operations of Hydro Québec all were allowed different capital structures and equity risk premiums.

In Ontario, both approaches have been used. The two large gas distributors (Enbridge Gas and Union Gas) historically have been allowed the same deemed common equity ratio, but Union is allowed a somewhat higher risk premium. Natural Resource Gas (NRG), a very small gas utility, had, between 1997 and 2006, been allowed a higher common equity ratio than Enbridge and Union, with a common equity return equal to that of Enbridge. When NRG refinanced its capital structure in 2006, the OEB reduced NRG's deemed equity ratio to a level close to the actual level, and increased its equity risk premium (above that of Enbridge Gas).

For the electricity distributors, in 2000, the OEB established different deemed capital structures for different tiers of utilities, based on size, where size was used as a proxy for differences in business risk. The same equity return was then applied to all the individual utilities. In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (*Report*), issued December 20, 2006, the Board has issued new guidelines which use the same deemed capital structure for all the electricity LDCs (60% debt/40% equity as well as the same ROE). The *Report* does not reflect any change in the principle that the capital structure (or return on equity) should reflect the utilities' relative risk. Rather, the *Report* reflects the conclusion that size no longer represents an accurate proxy for risk. The 40% equity ratio adopted in the *Report* represents Board Staff's proposal, which took into account the allowed common equity ratios for the gas utilities and the conclusion that a thicker common equity ratio is warranted for the electricity distributors. The rationale for this conclusion was that the risks of the gas utility business have been examined thoroughly through the regulatory process, unlike the electricity distribution industry, and that the electricity distribution industry requires significant investment in infrastructure, which imposes additional risks on the electricity distributors relative to the gas utilities.

ACTUAL vs. DEEMED CAPITAL STRUCTURE: PROS AND CONS

The advantages of using an actual capital structure are that:

1. it leaves the choice of capital structure to management, whose expertise in financial matters is superior to that of the regulator;

2. it allows, in principle, the actual capital costs of the utility to be recovered;

3. it recognizes that there is no widely agreed-upon measurement of the optimal capital structure; and

4. it recognizes that the factors such as the lumpiness of capital expenditures may not permit the utility to manage its actual capital structure to the ratios that would otherwise be deemed.

The principal advantages of a deemed capital structure are:

1. its use is compatible with basic finance theory that the opportunity cost of capital reflects the use of funds, that is the risk of the enterprise in which funds are invested, not the overall cost of funds to the entity that raises the capital;

2. it ensures that the ratepayer is protected from the riskier operations of a parent company; and,

3. it will result in more stable rates than using an actual capital structure that might change materially from year to year.

ISSUES IN SELECTING THE DEEMED CAPITAL STRUCTURE FOR REGULATED OPERATIONS

The selection of the appropriate deemed capital structure for regulated operations is based in large part on an assessment of the stand-alone business risks of those operations and on the resulting stand-alone financial metrics for those operations. The latter is to ensure that the regulated operations could, on a stand-alone basis, access the capital markets on reasonable terms and conditions without being subsidized by the unregulated operations.

If the deemed capital structure is to be in place for multiple years without review, e.g., during a PBR term, the proposed deemed ratio should be sustainable over that period. This is not usually an issue for an investor-owned utility that can seek equity infusions from its parent during that period to maintain the actual equity ratio close to the deemed level, but may be an issue for a publicly-owned utility facing material capital expenditures but access to equity only through management of dividend payments.

For an enterprise with both utility and non-utility operations, the utility may be required to demonstrate that the deemed equity ratio for the utility operations is not subsidizing the non-utility operations. To illustrate, assume a company which has 50% of its assets in utility and non-utility operations respectively. The consolidated common equity ratio of the company is 45%. A reasonable deemed common equity ratio for the utility operations is determined to be 50%. If the deemed equity ratio for the utility operations were indeed set at 50%, the implied common equity ratio of the non-utility operations would be only 40%.[118] Thus, unless there were evidence that the returns being earned by the non-utility operations were at a level that was compatible with the 40% implied equity ratio, an inference might be drawn that, at a 50% deemed equity ratio, the regulated operations (and ratepayers) are subsidizing the unregulated operations. It is important to ensure that the proposed deemed capital structure avoids potential cross-subsidization.

[118]The calculation is as follows:

$$\text{40\% non-utility equity ratio} = \frac{\text{45\% corporate equity ratio} - (\text{50\% utility assets x 50\% utility equity ratio})}{\text{50\% non-utility assets}}$$

IMPLEMENTATION OF A DEEMED CAPITAL STRUCTURE

The use of a deemed capital structure requires matching the capital structure to the rate base. The rate base, in principle, in its entirety is intended to be a representation of the amount of investor-supplied capital required to provide utility service. Ratepayer provided funds that are used to finance utility assets represent no cost capital. No cost capital (e.g., deferred taxes) should be deducted from rate base (or included in capital structure at a 0% cost rate).

To the extent that there are no specific debt issues that can be separately identified with the unregulated operations, actual long-term debt can be attributed to the deemed capital structure to the extent required to bring the rate base and deemed capital structure into balance. If the deemed equity and allocation to the utility capital structure of 100% of the actual long-term debt available does not equate rate base and capital structure, i.e., capital structure remains lower than rate base, the remaining gap is "plugged" by deeming sufficient debt to create a balance between the two.[119] The choice of short-term or long-term debt as the "plug" should be based on the nature of the shortfall between the two.[120] If, for example, the difference is primarily attributable to differences in the way working capital is estimated for regulatory purposes (lead/lag study) versus financial statement purposes, reflecting seasonal usage of short-term debt, the plug should attract a short-term debt cost. If, however, the difference were attributable to deeming a lower common equity ratio than the actual equity available, the "plug" should reflect the long-term nature of the assets and thus be deemed as, and costed at, a long-term debt rate.

[119] In its *Report* for the electricity distributors, the Board has fixed the short-term debt proportion at 4% of rate base. A cap on the short-term debt would require any additional "plug" that is required to equate rate base and capital structure to be deemed as long-term debt.

[120] In certain cases, where actual equity exceeds the deemed level, the "plug" is a reduction to capitalization. The cost rate on the "plug" has typically been deemed at a cost that reflects the rate achievable if the excess capitalization had been invested.

APPENDIX B

THE CAPITAL ATTRACTION AND COMPARABLE EARNINGS STANDARDS

Two standards for a fair return have arisen from the legal precedents for establishing a fair return, the capital attraction and comparable earnings standard. The principal Court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923)*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

In *Northwestern*, Mr. Justice Lamont stated

> 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 *Bluefield*, the criteria for a fair return were described as follows:

> 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.

In *Hope*, Justice Douglas stated,

> By that standard the return on 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 fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction and comparable earnings standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, *Hope* opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination. The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment.

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. For regulated utilities historic costs have been substituted for marginal or incremental costs for two reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets.

The current cost of attracting capital is measured by reference to market values. The discounted cash flow test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms).

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services; raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

Therefore, when the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value.

APPENDIX C

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F + \beta(R_M - R_F)},$$

Where:

R_F = risk-free rate
β = covariability of the security with the market (M)
R_M = return on the market.

The model is based on restrictive assumptions, including:

1. Perfect, or efficient, markets exist where,

   a. each investor assumes he has no effect on security prices;
   b. there are no taxes or transaction costs;
   c. all assets are publicly traded and perfectly divisible;
   d. there are no constraints on short-sales; and,

e. the same risk-free rate applies to both borrowing and lending.

2. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance }(R_E, R_M)}{\text{Variance }(R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

RISK-FREE RATE

1. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

2. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

   a. The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government has been in a surplus position for nine years, which has reduced its financing requirements. However, the demand for long-term government securities by institutions (e.g., pension funds) that match assets and liabilities has not declined. The pension funds, which are key purchasers of long-term government bonds, are typically buy and hold investors, which means that the government bonds in their portfolios do not trade. Thus, there is the potential not only for a scarcity premium in prices due to the demand for long-term government bonds, but also potential illiquidity in the market.

b. Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term average market risk premium.

c. Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The need to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM.

EQUITY MARKET RISK PREMIUM

1. Equity Risk Premium and Historic Data

The equity market risk premium is typically measured largely by reference to historic data. Adjustments are then made to capture (a) changes that have occurred in the underlying markets over time, or (b) perceived differences between what investors actually achieved and what they may have expected on an *ex ante* basis. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future (expected) risk premium. In summary, the link between the historic and the expected risk premium is subject to considerable judgment.

2. Factors specific to the Canadian historic risk premium data are problematic.

a. The Canadian equity market has undergone significant structural changes over the periods typically used to measure historic risk premiums. The historic market returns reflect in considerable measure a resource-based economy. At the end of 1980, no less than 46% of the market value of the TSE 300 was resource-based stocks.[121] By comparison, at the end of 2000, the resource-based percentage of the S&P/TSX Composite had declined to 18.4%. The influence of technology-intensive and service-related sectors on the index, in comparison had risen markedly. In particular, financial services had become a key sector of the equity composite. Table C-1, which compares the year-end 1980 and 2000 market weightings of the financial services and technology sectors, highlights the changes that occurred between 1980 and 2000.

[121] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

Table C-1

	1980	**2000**
Biotechnology/ Health Care/ Pharmaceuticals	0.0%	2.8
Information Technology	0.9%	24.1
Telecommunication Services	4.8%	6.5
Media & Entertainment	0.6%	4.1
Financial Services	13.5%	24.1
	19.8%	61.1

Source: *TSE Review*, December 1980 and December 2000.

By the end of August 2007, with the run-up in commodity prices since mid-2004, (and, to a lesser extent, with the implosion of the information technology sector in 2001), the resource-based sectors (comprised of the Energy sector and the largely mining-based Materials sector) once again have become a dominant component of the equity market, accounting for 43.5% of the total market value of the S&P/TSX Composite, with financial services second. With almost 75% of the S&P/TSX Composite's market value in three sectors, the Energy sector at 27% of the total market value of the Composite, the Financial sector at 31% and Materials at 17%, the Canadian market has, to some extent, had characteristics of market sectors, rather than of a diversified portfolio.

By comparison, the U.S. market is significantly more balanced among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at August 31, 2007 demonstrates the difference.

Table C-2

Sector	Canada S&P/TSX Composite	U.S. S&P 500
Consumer Discretionary	5.2%	9.8%
Consumer Staples	2.6%	9.5%
Energy	27.0%	11.1%
Financials	30.7%	20.1%
Health Care	0.6%	11.7%
Industrials	5.7%	11.4%
Information Technology	4.3%	16.3%
Materials	16.6%	3.1%
Telecommunication Services	5.8%	3.7%
Utilities	1.5%	3.4%

Source: *TSX Review* August 2007 and Standardandpoors.com.

b. Even within the remaining 25% of the Canadian market (the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, retailing and health care.

c. The historic average achieved returns of the TSE 300 Index have been significantly affected by the relatively mediocre performance of commodity-linked securities over the long-term. From 1956-2003 (the longest period for which consistent data exist for the individual TSE 300 sub-indices), the average returns of the commodity-based sectors were exceeded by the returns of virtually every other sector of the TSE 300.[122] Because the long-term returns of the various sectors are inconsistent with their relative risk, the achieved returns for the market composite may not accurately reflect what investors had expected.

d. In 2005, the S&P/TSX Composite underwent a significant change with the inclusion of income trusts. Income trusts, which just five years ago, had a market capitalization of approximately $20 billion, had a market capitalization of approximately $189 billion at the end of 2006, accounting for approximately 9% of the total market value of the TSX. Despite the change to the income tax treatment of income trusts announced in October 2006, income trusts significantly outperformed the "conventional" equity markets during the period for which income trust market data are readily available. The annual total return for the S&P/TSX Capped Income Trust Index over the 1998-2006 period averaged 16.4%, compared to 9.4% for the S&P/TSX Composite Index. The exclusion of income trust returns from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.

[122] The average (compound, or geometric) returns of the commodity-based sectors were as follows:

Metals/Minerals	7.8%
Gold	9.5%
Oil and Gas	9.5%
Paper/Forest	7.1%

By comparison, the corresponding simple average of the remaining sectors' returns over the same period was 10.3%.

e. The TSE 300 Index has been criticized for its lack of liquidity and for the quality and size of the stocks it has contained. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

When the TSE 300 was overhauled (becoming the S&P/TSX Composite in May 2002), 275 companies were initially included, instead of the previous 300.[123] At December 31, 2005 there were 278 companies in the Composite, including the recently added income trusts.

f. The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies. In mid-2000, before the

[123] The overhaul of the composite index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index.

debacle in Nortel Networks' stock value, Nortel shares alone accounted for 34.6% of the total market value of the TSE 300. To put this in perspective, the largest stock in the S&P 500 at that time (General Electric) accounted for only 4% of the S&P 500's total market value. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the TSE 300 regarding the forward-looking market risk premium.

g. The returns in the Canadian market have historically been negatively impacted by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs). In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased returns by 1% and that a 30% limit would increase returns a further 0.5%.[124] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[125] which

[124] *Paving the Way for Change to RRSP Foreign Content Rules*, Tom Hockin, President and CEO IFIC, January 31, 2000.
[125] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

supported the removal of the cap.[126] The *Globe and Mail* reported that the removal of the foreign content cap is expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[127] The Foreign Property Rule was finally eliminated in August 2005 effective January 1, 2005.

h. The achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in interest rates and concomitant increases in total bond returns. The prevailing low level of interest rates relative to the historic total returns on bonds indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns. Consequently the historic equity risk premium understates the future risk premium.

[126] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[127] Rob Carrick, *Finance: Your Bottom Line*, Globeandmail.com, February 23, 2005.

3. Use of Arithmetic Averages to Estimate the Equity Market Risk Premium

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance,* Boston: Irwin McGraw Hill, 2000 (p. 157), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for this purpose is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.[128]

[128] An illustration from Ibbotson Associates demonstrating why the arithmetic average is more appropriate than the geometric average for estimating the expected risk premium is presented in Figure C-1.

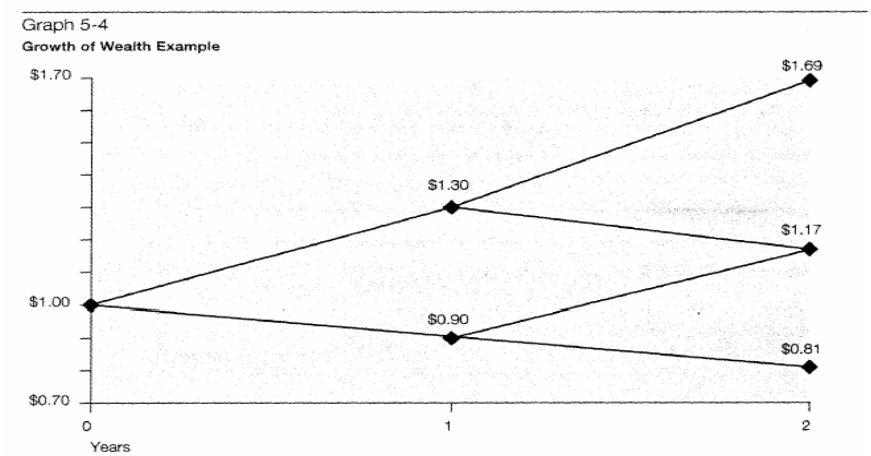
Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2005,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year — +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)x(1-0.10)]^{1/2} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x $1.69)	=	$0.4225
+	(0.50 x $1.17)	=	$0.5850
+	(0.25 x $0.81)	=	$0.2025
	Total		$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \text{ x } (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1 \text{ x } (1+0.0.082)^2 = \$1.17$$

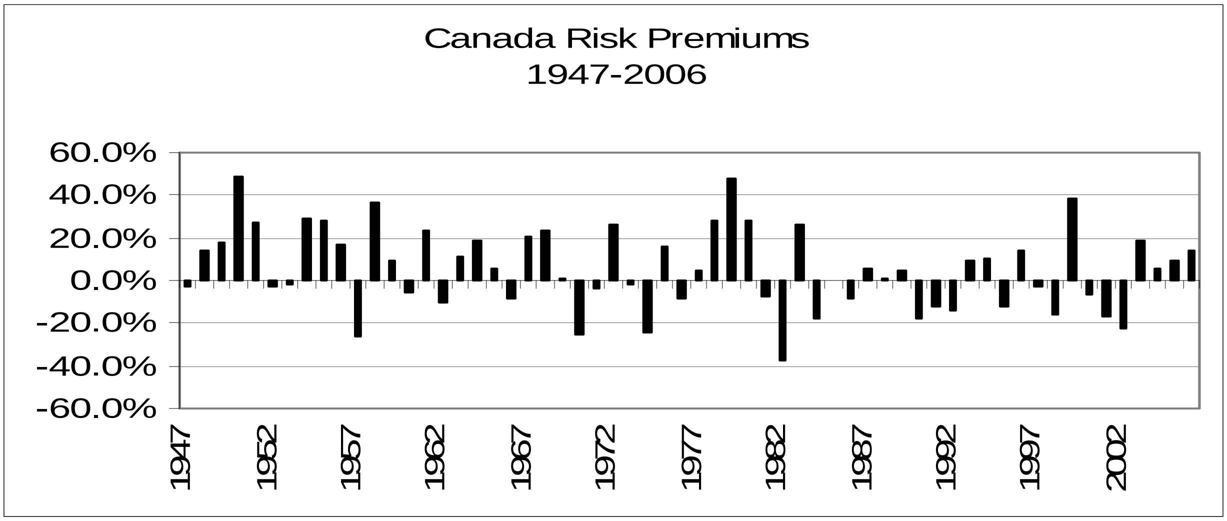
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historic annual risk premiums. The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[129]

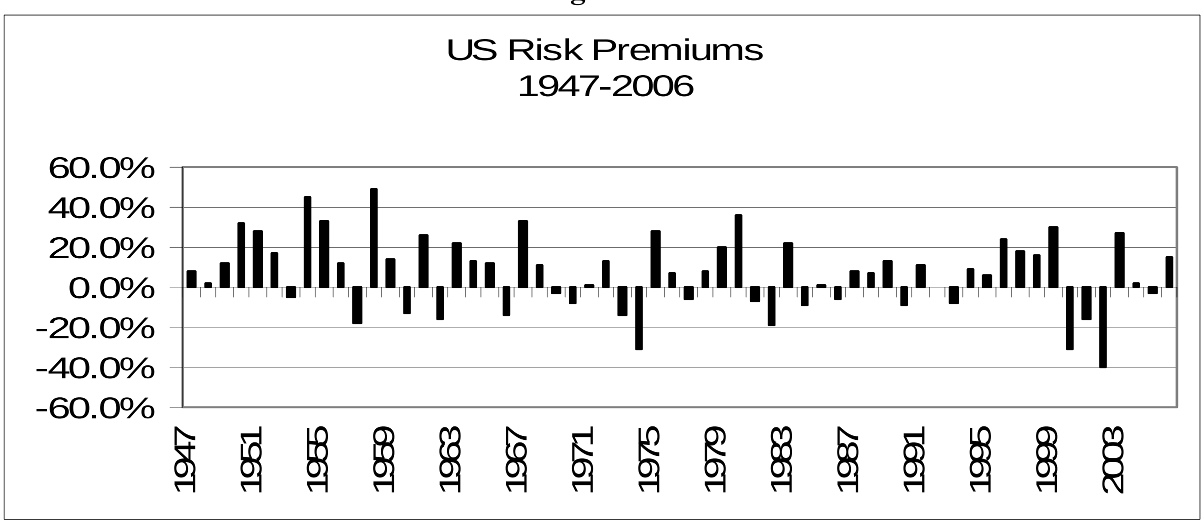
[129] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2006 is 0.06 for Canada and −0.05 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Figure C-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006*.

Figure C-2



Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2007 Yearbook.*

FUTURE vs. HISTORIC RISK PREMIUMS

1. Analysis of Trends in Canadian and U.S. Stock and Bond Returns

Table C-3 on the following page compares the historic Canadian and U.S. stock returns, bond returns, and equity risk premiums, over 10-year periods.

Table C-3

Time Period	Stock Returns		Bond Returns		Risk Premiums	
	Canada	U.S.	Canada	U.S.	Canada	U.S.
1947-1956	18.9%	19.4%	1.4%	0.8%	17.5%	18.5%
1957-1966	8.3%	10.5%	2.9%	3.0%	5.4%	7.5%
1967-1976	7.5%	8.4%	5.1%	4.6%	2.4%	3.8%
1977-1986	17.8%	14.6%	11.4%	10.7%	6.4%	3.9%
1987-1996	10.9%	16.0%	12.1%	10.0%	-1.2%	6.1%
1997-2006	11.0%	10.0%	8.7%	8.2%	2.3%	1.8%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006* and Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2007 Yearbook*.

The decade-by-decade averages suggest that there has been no upward or downward trend in the stock returns. By comparison, the bond returns generally exhibit an increase over time. The pattern in the bond returns results from:

- low bond returns in the 1950s-1970s, as rising interest rates produced capital losses on bonds;

- high bond returns in the 1980s, corresponding to the high rates of inflation, which pushed up bond yields; and,

- high bond returns in the 1990s and first half of the 2000s, reflecting the decline in interest rates and resulting capital appreciation of bonds, leading to total returns well in excess of the yields.[130]

A similar conclusion regarding trends in the risk premium can be drawn from an analysis of rolling and cumulative averages of Canadian and U.S. stock and bond returns. The following averages were calculated for this analysis:

- Twenty-five year rolling arithmetic averages of Canadian and U.S. equity and long-term government bond returns (1947-2006).

- A series of cumulative average equity and bond returns for Canada and the U.S. The first average starts in 1947, covering 25 years (1947-1971). The second average incorporates 26 years, etc. The final average encompasses the full 1947-2006 period.

- A second series of cumulative average returns, where the first average includes the most recent 25 year period (1982-2006); each subsequent average includes an additional prior year.

[130] The bond yield is, in fact, an estimate of the expected return.

The following table summarizes the resulting averages for the equity market returns.[131] The summary of the various averages indicates that the historic equity market returns have not exhibited a secular upward or downward trend, but are within the following ranges:

Table C-4

	Canada	U.S.
25-Year Rolling Averages:		
Range	9.6-14.5%	9.4-18.0%
Average of Averages	11.8%	12.5%
± 1 standard deviation	10.7-12.8%	10.4-14.6%
Increasing Averages (1947+):		
Range	11.4-13.6%	11.5-14.6%
Average of Averages	12.6%	13.1%
± 1 standard deviation	12.0-13.1%	12.4-13.8%
Increasing Averages (2005+):		
Range	10.8-13.3%	11.6-14.6%
Average of Averages	11.9%	12.8%
± 1 standard deviation	11.3-12.6%	11.9-13.7%

Source: Schedule 4.

The analysis also shows achieved total bond returns have experienced an upward trend, similar to that identified in the decade-by-decade returns described earlier. That trend is unlikely to continue, as recent low levels of interest rates limit future capital gains; it is more likely, in an environment of rising interest rates that bonds would experience capital losses, and the achieved risk premiums will rise.

[131] All of the averages appear on Schedule 4.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.5%, based on both the Canadian and U.S. equity market returns. Based on the 2008 forecast for long Canada bond yields of 5.0%[132], and an expected equity market return of 11.5-12.5%, the indicated market risk premium would be in the range of 6.5-7.5%, or approximately 7.0%. Based on the longer-term forecast for long Canada bond yields of approximately 5.25%,[133] the indicated market risk premium is 6.25-7.25%.

2. Trends in Price/Earnings Ratios

Several studies of historic and equity risk premiums conclude that past equity markets are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[134] of the S&P 500 averaged 14 times from 1926-1989, with no discernible upward trend.[135] From 14.7 in 1989, the P/E ratio rose to a high of 32.3 in 1998, and averaged 23 from 1990-2000. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall

[132] Based on the August 2007 *Consensus Forecast*.
[133] The 2008 forecast is, as previously noted, 5.0%. Consensus Economics, *Consensus Forecasts*, April 2007 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2009 to 2017. Adding a spread of approximately 10 (as of August 2007) to 30 (historic average) basis points to the 5.0% forecast results in a 30-year Canada bond yield forecast of close to 5.25%.
[134] Coincident price and earnings.
[135] The average from 1947-1989 was 13.3 times.

Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[136] Nevertheless, the P/E ratio for the S&P 500 remains above the average for 1947-1989, but within the historic range.[137]

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1947 and 1990, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved equity returns for the S&P 500 averaged 12.3% (geometric average) to 13.5% (arithmetic average) from 1947-1989. The corresponding returns from 1947-2006 were 11.9% (geometric average) to 13.2% (arithmetic average). Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1947-2006 period than over the 1947-1989 period. Stated differently, the increase in P/E ratios during the 1990s has not resulted in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic levels of 12.0-13.0% is not unreasonable. Relative to the consensus forecast yield for 30-year Treasury bonds for 2007 and for the longer term of approximately 5.3%,[138] the risk premium would be approximately 6.75-7.75%.

My review of Canadian equity returns over the same period indicates similar results. The 1947-1989 returns for the Canadian equity market were 11.9% (geometric average) to 13.1%

[136] Lowered expectations for the equity market have led investors to focus elsewhere for superior risk/reward opportunities, e.g., real estate, and private equity, suggesting the possibility that recent expectations for the public equity market may be out-of-line with return requirements. Investors' experiences during the equity market "bust" have been a key factor in explaining the recent burgeoning of the income trust market in Canada.

[137] At the end of August 2007, the S&P 500 P/E ratio was 17.3.

[138] For 2008-2017; Blue Chip *Financial Forecasts*, August 1, 2007 and June 1, 2007.

(arithmetic average), very similar to the U.S. returns, and higher than the average of the 1947-2006 returns. In relation to the 2008 and long-term forecasts of the 30-year Canada bond yield, 5.0% and 5.25% respectively, and an expected value of the Canadian equity market returns in the range of 12.0-13.0%, the expected value for the equity risk premium would be in the range of approximately 7.0-7.75%.

The analysis of stock and bond returns in Canada and the U.S. over the 1947-2006 period reveals no upward or downward trend in market equity returns. Nevertheless, the achieved risk premiums have declined. The arithmetic average achieved risk premium in Canada from 1947-1989 was 7.6%; in the U.S., it was 8.5%. By comparison, the corresponding 1947-2006 risk premiums were 5.5% and 6.9% respectively. An analysis of the data shows that high bond returns over the period 1990-2006 are the principal reason for the decline in experienced risk premiums, not a downward trend in stock returns. The average bond return from 1990-2006 was 10.6%, compared to the corresponding average yield on long-term Canada bonds of 6.8%.

Over the entire 1947-2006 period, the average return (income plus capital appreciation) on long Canada bonds was approximately 7.0%. With interest rates currently at historically low levels (approximately 4.5% at the end of August 2007), and more likely to increase rather than decrease further, the 1947-2006 average bond return of approximately 7.0% overstates the forward-looking expectation of bond returns, as embedded in both current yields and long-term forecasts. The current low level of long-Canada yields limits the possibility of future capital gains, which arise from a decline in interest rates. Thus, a reasonable expected value of the long Canada bond return is the forecast long Canada yield, rather than the historic average.

RELATIVE RISK ADJUSTMENT

1. Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

a. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

b. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

c. The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market)[139] are a good measure of the relative return requirement.

d. Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have

[139] The beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

Fama and French have developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM.[140]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are

[140] The additional factors are size and book to market.

> very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[141]

2. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available;

[141] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

(b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table C-5

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 6, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table C-5 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2006, the longest period for which data for the new

Composite and its sector components are available; (b) 1988-1997,[142] and (c) the most recent 10-year period ending 2006.

That analysis showed the following:

Table C-6

Returns Measured Over:	Coefficient on Beta	R^2
1988-2006	-.043	23%
1988-1997	-.017	1%
1996-2006	-.098	45%

Source: Schedule 6, page 2 of 2.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship.

3. Impact of Interest Sensitivity of Utility Shares on Relative Risk Adjustment

The single equity beta does not capture the interest sensitivity of utility shares. The following analysis demonstrates how explicitly incorporating interest sensitivity impacts the relative risk assessment.

[142] The use of this sub-period was intended to ensure elimination of the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.

A regression of the monthly returns on the TSE Gas/Electric Index against the TSE 300 over the period 1970-August 1999[143] shows the following:

$$\text{Monthly TSE Gas/Electric Return} = 0.0054 + 0.58 \left\{ \text{Monthly TSE 300 Return} \right\}$$

t-statistic = 16.5

R^2 = 43.3%

The relationship quantified in the above equation suggests a relative risk adjustment of close to 0.60. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 43%. That means 57% of the volatility remains unexplained.

When the analysis is expanded to include Government of Canada bond returns, the following regression is produced:

$$\text{Monthly TSE Gas/Electric Return} = 0.0018 + 0.48 \left\{ \text{Monthly TSE 300 Return} \right\} + .52 \left\{ \text{Monthly Long Canada Bond Return} \right\}$$

t-statistics = 14.5 (TSE 300), 9.5 (Long Canada Bond)

R^2 = 55.0%

When interest rates (as proxied by government bond returns) are added as a further explanatory variable, more of the observed volatility in utility stock prices is explained (55% versus 43%).

The second regression equation suggests that utility shares have had approximately 50% of the volatility of the equity market as well as approximately 50% of the volatility of the bond market,

[143] Excludes the anomalous market “bubble and bust”/“Nortel effect” period.

consistent with utility common stocks' interest sensitivity. Using an expected equity market return of 11.5%, and a long Canada bond return equal to the 2008 forecast 30-year Canada yield of 5.0%, the equation indicates an expected utility return of 10.4%. When the 10.4% utility return is expressed as an equity risk premium relative to the 5.0% long Canada yield, the indicated relative risk adjustment is close to 83%.[144]

[144] $\frac{10.4\% - 5.0\%}{11.5\% - 5.0\%} = .83$

APPENDIX D

DCF-BASED RISK PREMIUM TEST

SELECTION OF LOW RISK BENCHMARK UTILITIES

For the estimation of the benchmark return, a sample of low risk U.S. utilities was selected, comprised of all electric utilities and gas distributors satisfying the following criteria:

1. Classified by *Value Line* as an electric utility or a gas distributor;

2. Standard & Poor's business risk profile score of "5" or less;

3. Standard & Poor's debt rating of A- or higher;

4. Not presently being acquired; and,

5. Consistent history of analysts' forecasts.

The 13 utilities that met these criteria are listed on Schedule 13.

CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the 13 utilities in the sample over the period 1993-2007 (2nd Qtr).[145] The monthly DCF cost for each utility was estimated as the sum of the utilities' I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S median earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 12). The monthly sample average ERPs were used to estimate the regression equations found in Chapter III.C.b.4 of the testimony.

[145] Subsequent to Open Access for natural gas transmission implemented via FERC Order 636.

APPENDIX E

DISCOUNTED CASH FLOW TEST

DCF MODELS

Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries.

Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value. As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not forecast beyond five years. Hence, in that context the current market price and dividend yield would not explicitly anticipate any changes in the outlook for growth.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } \mathbf{(k)} = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[146]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

[146] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

Two-Stage Model

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1 Growth), but, in the longer-term (from Year 6 onward) to migrate to the expected long-run rate of growth in the economy (GDP Growth). All industries go through various stages in their life cycle. Utilities are considered to be the quintessential mature industry. Mature industries are those whose growth parallels that of the overall economy.

The use of forecast GDP growth as the long-term growth component is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth in its standard DCF models for gas and oil pipelines.

Using the two-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor.

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

Cash flows from Year 6 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

SELECTION OF PROXY BENCHMARK UTILITIES

The same sample of benchmark utilities was used as for the DCF-based risk premium test. The selection criteria for these low risk utilities are described in Appendix D.

INVESTOR GROWTH EXPECTATIONS

The application of the constant growth model relies principally on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S. The application of the two-stage model relies upon the I/B/E/S consensus earnings forecasts as the estimate of investor growth expectations during Stage 1. The expected nominal long-run rate of growth in the economy (GDP) is based on the consensus of economists' long-term forecasts (published twice annually) found in *Blue Chip Economic Indicators* (March 10, 2007). The consensus forecast rate of growth in the long-term (2009-2018) is 5.1%.

Empirical studies that conclude that investment analysts' growth forecasts serve as a better surrogate for investors expectations than historic growth rates include: Lawrence D. Brown and Michael S. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings", *The Journal of Finance*, Vol. XXXIII, No. 1, March 1978; Dov Fried and Dan Givoly, "Financial Analysts Forecasts of Earnings, A Better Surrogate for Market Expectations", *Journal of Accounting and Economics,* Vol. 4 (1982); R. Charles Moyer, Robert E. Chatfield, Gary D. Kelley, "The Accuracy of Long-Term Earnings Forecasts in the Electric Utility Industry", *International Journal of Forecasting* Vol. I (1985); Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management*, Spring 1986, and, James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History", *The Journal of Portfolio Management*, Spring 1988; David Gordon, Myron Gordon and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

The Vander Weide and Carleton study cited

> found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price [and that these results] also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.

The Gordon, Gordon and Gould study concluded,

> …the superior performance by KFRG [forecasts of [earnings] growth by securities analysts] should come as no surprise. All four estimates [securities analysts' forecasts plus past growth in earnings and dividends and historic retention growth rates] rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth.

In the application of the DCF test, the reliability of the earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. For the sample of low risk utilities used in the DCF test (as well as the DCF-based equity risk premium test to estimate the benchmark return on equity), the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1993-2007 (2^{nd} Qtr) period of analysis was 4.7%. That growth rate is lower than the expected long-term nominal growth in the economy as a whole over the same period.[147] An expected growth rate that is close to that of the economy as a whole would not be out-of-line with the level of growth investors could reasonably expect in the relatively mature utility industries over the longer-term.

[147] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1993-2007), has been 5.3% over the same period covered by the DCF-based equity risk premium test.

APPLICATION OF THE DCF MODELS

Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk gas and electric utilities using the following inputs to calculate the dividend yield:

1. the most recent annualized dividend paid as of July 31, 2007 as D_o; and,
2. the average of the daily close prices for the period July 16 to August 15, 2007 as P_o.

For the expected growth rates, the July 2007 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The DCF estimates of the cost of equity for the benchmark sample based on the constant growth model were approximately 9.3% (See Schedule 14).

Two-Stage Model

The two-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), and forecast growth in the economy thereafter (Stage 2). The consensus long-run (2009-2018) expected nominal rate of growth in GDP, as noted above, is 5.1%.

The two-stage DCF model estimates of the cost of equity for the benchmark low risk U.S. utility sample (Schedule 15) are as follows:

Mean	9.4%
Median	9.5%

Results of the Constant Growth and Two-Stage Models

The results of the two models indicate a required "bare-bones" return on equity of approximately 9.25% (constant growth model) to 9.5% (two-stage model).

APPENDIX F

COMPARABLE EARNINGS TEST

SELECTION OF CANADIAN INDUSTRIALS

The selection process starts with the recognition that industrials generally are exposed to higher business risk, but lower financial risk, than a benchmark Canadian utility. The selection of industrials focuses on total investment risk, i.e., the combined business and financial risks. The comparable earnings test is based on the premise that industrials' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting selection of industrial samples of reasonably comparable investment risk to a benchmark Canadian utility.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[148] The resulting universe contained 479 firms. From this group of 479 companies, all firms with missing book equity or negative common equity during the period 1994-2006 as well as 2006 equity below $50 million were removed (76 companies remaining). Next, all companies that paid no dividends in any year 2001-2006 were removed (46 companies remaining). To remove small and/or thinly traded companies, all companies that traded fewer than 125,000 shares in

[148] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

2006 were eliminated, as were those companies with fewer than five years of market data available (leaving 43 companies). To ensure that relatively low risk unregulated companies were selected, all companies with five-year "raw" betas ending December 2006 over 1.0 were removed. The resulting group contained 40 companies.[149] Next, those companies whose 1994-2006 returns fall outside ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (30 companies remaining). Finally, those companies whose stock was ranked "Higher Risk" or "Speculative" by the Canadian Business Service (CBS),[150] whose debt is rated non-investment grade i.e., BB+ or below by either DBRS or Standard & Poor's, or for which none of the agencies report a rating, were eliminated. The final sample of low risk Canadian industrials is comprised of 20 companies (Schedule 16).

TIME PERIOD FOR MEASURING RETURNS

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1994-2006 encompasses both years of economic expansion and contraction. Over the period 1994-2006, the experienced returns on equity of the sample of 20 industrials were as follows.

[149] SNC-Lavalin was removed due to its purchase of regulated electric transmission assets in Alberta; Canadian Pacific Railway was also eliminated due to its reorganization in 2000, which rendered its historic data series inconsistent; Canadian National Railway was removed as it was controlled by the Federal Government through November 1995; Foremost Income Fund and North West Co. Fund, were removed because they are income trusts.
[150] Canadian Business Service (CBS) ranks stocks "Very Conservative", "Conservative", "Average", "Higher Risk", or "Speculative".

Table F-1

Returns on Average Common Equity for Low Risk Canadian Industrials (1994-2006)	
Average	13.3%
Median	12.8%
Average of annual medians	13.3%

Source: Schedule 17.

Based on these data, the returns are in the approximate range of 12.75-13.25%.

The average nominal economic growth for Canada during the 1994-2006 business cycle was 5.4%, compared to the consensus forecast for real growth of 2.7%, and for inflation (CPI) of 2.0% for the period (2008-2017)[151], which suggests nominal long-term GDP growth of approximately 4.75%. While nominal growth is expected to be moderately lower relative to the past business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

[151] Consensus Economics, *Consensus Forecasts*, April 2007.

RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian industrials relative to a benchmark Canadian utility, comparisons of the various risk measures indicate that they are in a similar risk class. The median CBS stock rating for the industrials is "Conservative", compared to the median of "Very Conservative" for the investor-owned Canadian utilities with publicly-traded stock. The median S&P and DBRS debt ratings for the industrials are BBB+ and BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 16 and 26). The median adjusted beta for the industrials was 0.62 for the five year period ending December 2006 (see Schedule 16), compared to the adjusted betas for Canadian utilities over the same time period of approximately 0.50-0.55. (Schedule 8)

The estimate of a normal cycle average level of returns for low risk Canadian industrials is in the approximate range of 12.75-13.5%. The comparative risk data indicate, on balance, the Canadian industrials are somewhat riskier than a benchmark utility. The somewhat higher risk of the industrials relative to a benchmark utility requires a modest downward adjustment to the industrials' 12.75-13.25% average ROE to a range of 12.25-12.75% (mid-point of 12.5%).

SELECTION OF U.S. INDUSTRIALS

The U.S. industrials were selected using similar criteria to the selection of Canadian industrials. The initial universe consisted of all firms actively traded in the U.S. from S&P's Compustat database in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[152] The resulting universe contained 2,643 firms. All non-U.S. companies were then removed, leaving 2,353. From this group of 2,353 companies, all firms with missing or negative common equity during the period 1994-2006 or with 2006 common equity less than $50 million were removed (681 companies remaining). To remove thinly traded companies, all companies that traded fewer than 125,000 shares in 2006 were eliminated (leaving 658 companies). Next, all companies that paid no dividends in any year 2001-2006 were removed (310 companies remaining). To ensure that low risk companies were selected, all companies with five year "raw" betas ending December 2006 over 1.0 were removed (leaving 221 companies). Next, those companies whose 1994-2006 returns were greater than ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (leaving 182 companies). Finally, those companies whose debt is rated non-investment grade i.e., BB+ or below by Standard & Poor's, or for which the *Value Line* Safety Rank was equal to "4" or "5",[153] were eliminated. The final sample of low risk U.S. industrials is comprised of 157 companies

[152] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.
[153] *Value Line*'s Safety Rank is a measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other *Value Line* indexes – the Price Stability Index and the Financial Strength Rank. Safety Ranks range from "1" (highest) to "5" (lowest).

(Schedule 18). The returns for the sample of U.S. industrials are summarized in Table F-2 following.

Table F-2

Returns on Average Common Equity for Low Risk U.S. Industrials (1994-2006)

Average	14.6%
Median	13.6%
Average of annual medians	14.5%

Source: Schedule 19.

Based on these data, the returns are in the approximate range of 13.5-14.5%.

Comparisons of the U.S. industrials' and utilities' risk measures indicate that the U.S industrials are of somewhat higher risk than the utilities. The median and mean *Value Line* Safety Ranks for the U.S. industrials are both "3", compared to the Safety Rank of "2" for TransCanada Corporation, the one regulated Canadian company with *Value Line* rankings.[154] The industrials' median and mean S&P debt ratings are BBB+ and A-, respectively, compared to the major Canadian utilities' S&P median and mean ratings of A- and to the benchmark low risk U.S. utilities' median and mean S&P debt ratings of A (see Schedules 13, 18 and 26). The most

[154] The mean and median Safety Ranks for the proxy sample of U.S. electric and gas utilities used to perform the DCF-based equity risk premium and discounted cash flow tests are "2" and "1" respectively; See Schedule 13.

recent median *Value Line* beta for the U.S. industrials was 0.95 (see Schedule 18), compared to the similarly calculated beta of 0.85 of the benchmark low risk U.S. utilities. A downward adjustment to the U.S industrial returns for the difference in betas indicates a risk-adjusted return of approximately 13.0%. The returns for the U.S. industrials as adjusted for relative risk then supports the reasonableness of the comparable earnings results as applied to the Canadian industrials.

The returns for the relatively low risk competitive U.S. firms confirm that the results of the comparable earnings test applied to unregulated Canadian firms are reasonable.

MARKET/BOOK RATIOS

Prior to its adoption of an automatic adjustment mechanism for ROE,[155] the OEB gave weight to the comparable earnings test "incorporating a market/book ratio adjustment".[156] In arriving at its recent decision for Terasen Gas (March 2006), the British Columbia Utilities Commission stated that it did not believe comparable earnings had outlived its usefulness, and that it may yet play a role in future ROE hearings. Nevertheless, the BCUC concluded that there was insufficient evidence before it regarding whether or not a market/book ratio adjustment was merited and, if so, how it might be accomplished.

[155] The OEB initially adopted an automatic adjustment mechanism for the natural gas distributors in March 1997.
[156] For example, in EBRO 470 (April 1991) for Union Gas.

The rationale for a market/book ratio adjustment to the comparable earnings test results has arisen on two grounds:

1. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.

2. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the "Q Ratio", a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.[157] Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the "Q Ratio" (market value/replacement cost) should trend toward 1.0.

The "Q Ratio" has since gained stature as an investment tool,[158] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

[157] The general idea had been expressed decades earlier by the economist John Keynes.
[158] The Federal Reserve Board tracks the "Q Ratio" of the U.S. equity market. It was the level of the "Q Ratio", along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

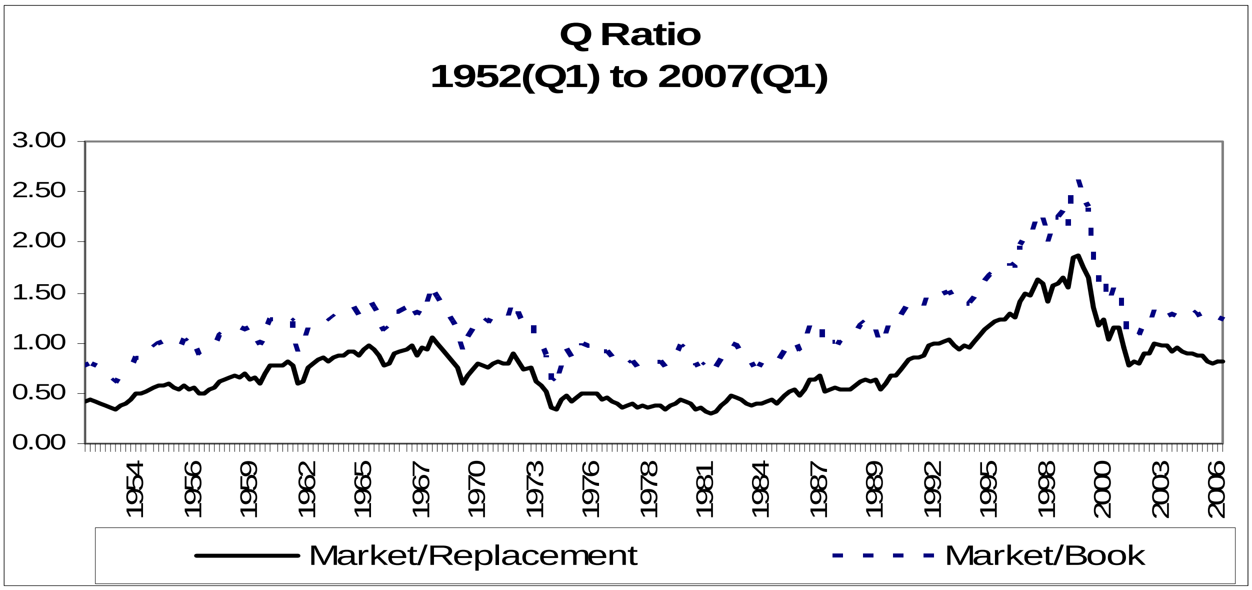
> Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin's work.
>
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. While the Q ratio – as Tobin's Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today. [emphasis added]

Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

As indicated in Figure F-1 below, market/replacement cost ratios, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations[159] has averaged approximately 60% lower than the market/book ratio.

[159] Based on non-farm, non-financial corporate businesses.

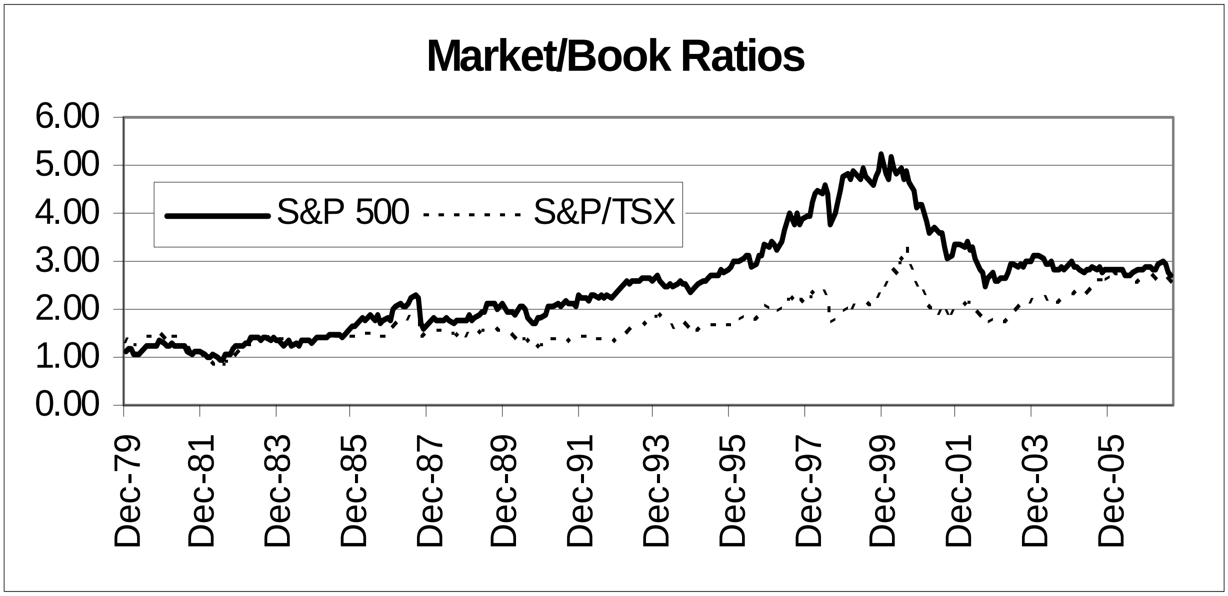
Figure F-1



Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the two samples of low risk unregulated firms used in the comparable earnings test, their market/book ratios were compared to those of the respective Canadian and U.S. market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2006.

Figure F-2



Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.7 times from 1980-2006, and approximately 2.1 times from 1994-2006, the period over which the comparable earnings test was conducted. Based on twenty-five years of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.7 times, not 1.0 times. Over the period 1994-2006 the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times, equal to the average for the S&P/TSX Composite. For the S&P 500, the market/book ratios were approximately 2.5 and 3.4 times, respectively, over the same two periods. For the sample of low risk U.S. unregulated firms, the average market/book ratio was 2.7 times from 1994-2006. The similar to lower average market/book ratios of the low risk samples relative to the overall equity market composites permit the inference that the sample average returns are not characterized by market power.

In summary, the comparable earnings results do not warrant an adjustment for market/book ratios.

APPENDIX G

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is "bare-bones" in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when industrials of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive industrials of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such industrials, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of industrials to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[160]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The

[160] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000. My home is currently worth $250,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $150,000, not the "book value" of my home, which reflects the original purchase price less the mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, application of an unadjusted market-derived cost of equity to the book value capital structure fails to recognize the higher financial risk and the higher cost of equity implied by the book value capital structures.

Two approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity. The first approach is based on the theory that the overall cost of capital does not change materially over a relatively broad range of capital structures. The second approach is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense.[161]

Schedules 20 and 22 provide the formulas and inputs for estimating the change in the cost of equity under each of the two approaches. The schedules show that a recognition of the difference in financial risk between the market value and book value capital structures of the publicly-traded Canadian utilities and the low risk U.S. utilities results in an increase in the cost of equity in the range of 0.85 to 2.05 percentage points. A minimal recognition of the higher financial risk in the book value capital structures supports a financing flexibility adjustment of no less than 50 basis points.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[162]

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[161] The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

[162] The financing flexibility allowance is estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x “bare-bones” Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a dividend payout ratio of 65% and a cost of equity of 10.0%, the indicated ROE is:

The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators. As a government-owned utility, OPG does not raise capital in the public equity markets; therefore it would not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the cost of equity and a fair return on the book value of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership.

OPG operates as a commercial entity. As such, the utility should be financed with a capital structure that, similar to investor-owned utilities, reflects its business risks and, in principle, would allow it to access the capital markets on reasonable terms and conditions on a stand-alone basis. An investor-owned utility can access the public equity markets to finance its "normal" capital program, as well as any extraordinary needs, and to maintain a balanced capital structure. OPG's access to equity is largely through retained earnings.

Consequently, OPG's need for financing flexibility is no less than that of an investor-owned utility. Thus, the financing allowance component of the fair return should be the same as for an investor-owned utility. Explicit inclusion of a financing flexibility allowance in the ROE for a government-owned utility has regulatory precedents. The government-owned utilities in both British Columbia and Alberta have been allowed returns that are equivalent to those of the

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$$\text{ROE} = \frac{1.075 \times 10\%}{1 + [.35\,(1.075 - 1.0)]}$$

$$\text{ROE} = 10.5\%$$

The difference between the ROE and the "bare-bones" cost of equity of 50 basis points is the financing flexibility allowance.

investor-owned utilities, which, in turn, include an allowance for financing flexibility. In Alberta, for example, in the recent Generic Cost of Capital decision (Decision 2004-052, July 2, 2004), the EUB allowed an adjustment of 50 basis points for flotation costs and financing flexibility to all of the utilities to which the decision applied, both investor- and government-owned.

The financing flexibility allowance for OPG should be, at a minimum, 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable earnings standard.

APPENDIX H

DEBT RATING AGENCY FINANCIAL METRIC GUIDELINES

DBRS
GENERAL STANDARDS RATING BBB TO "A" (QUANTITATIVE FACTORS)

	Regulated	Mixed	Unregulated
Percent Debt	60%-70%	50%-60%	50%
Fixed-charge Coverage	1.5x	1.5 - 2.0 x	2.0 x +
Cash Flow / Debt	0.10	0.10 - 0.15	0.15 - 0.20

Source: DBRS, *DBRS Methodology in Rating Utilities*, June 2002

MOODY'S
PRIMARY FINANCIAL RATIOS

Business Risk	Aa Medium	Aa Low	A Medium	A Low	Baa Medium	Baa Low	Ba Medium	Ba Low
FFO Interest Coverage (X)	> 6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
FFO/Debt (%)	>30	>22	22-30	12-22	13-25	5-13	<13	<5
Retained Cash Flow/Debt (%)	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Debt/Capital (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

Source: Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005

S&P INDUSTRY BENCHMARKS

Business Profile	AA		A		BBB		BB	
	Adjusted FFO interest coverage (x)							
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
	Adjusted FFO/average total debt (%)							
1	20	15	15	10	10	5	< 5.0	< 5.0
2	25	20	20	12	12	8	< 8.0	< 8.0
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9	N/A	N/A	65	45	45	30	30	20
10	N/A	N/A	70	55	55	40	40	25
	Adjusted total debt/total capital (%)							
1	48	55	55	60	60	70	> 70.0	> 70.0
2	45	52	52	58	58	68	> 68.0	> 68.0
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9	N/A	N/A	32	40	40	50	50	55
10	N/A	N/A	25	35	35	48	48	52

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak).
FFO -- Funds from Operations. N/A--Not applicable.

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 2006

APPENDIX I

TRANSLATION OF RETURN REQUIREMENT TO COMMON EQUITY RATIO

BACKGROUND

The benchmark utility return was developed from market data for all publicly traded Canadian utilities and a sample of low risk U.S. utilities determined to be of equivalent risk to a benchmark Canadian utility. OPG faces higher business risk than the typical Canadian utility and the sample of low risk U.S. utilities used in the estimation of the benchmark return on equity. The objective of this appendix is to quantify the deemed common equity ratio for OPG's regulated operations that is required to equate OPG's total business and financial risk to that of a benchmark utility. At the identified common equity ratio, the benchmark utility return on equity will be applicable to OPG.

METHODOLOGY

To quantify the equity ratio required for the benchmark utility return on equity to be applicable to OPG, the following steps were taken:

Select a sample of vertically integrated U.S. utilities that have a significant proportion of their assets devoted to generation ("high Gx"), i.e., that are closer in business risk to OPG's regulated operations than the low risk U.S. utility sample. [163]

1. Estimate the betas and CAPM costs of equity for the "high Gx" utility sample.

2. Disaggregate the betas for the "high Gx" sample companies to derive an estimate of the betas for the generation-only portion of their businesses.
    a. Select a sample of "wires-only" utilities and use to estimate the "wires-only" beta.
    b. Determine the proportion of assets for each company in the "high Gx" sample devoted to generation, wires and "other operations".
    c. Using the estimated beta for wires and assuming a market average beta of 1.0 for "other operations", derive the generation-only betas.

3. Combine the generation-only betas with my estimates of the market risk premium and risk-free rate to arrive at an estimate of the generation-only CAPM cost of equity. Since the capital structures of both samples (wires, and high Gx) used to derive the generation-only betas each contain close to 45% equity, the generation-only return requirement would apply to OPG's regulated operations as estimated if OPG's deemed common equity ratio were set at 45%.

[163] The capital markets in the U.S. and Canada are significantly integrated; there are no publicly traded companies in Canada with nuclear assets. Based on Standard & Poor's comments that due to deregulation in European power markets (S&P, "Credit Aspects of North American and European Nuclear Power", January 2006), nuclear operators were offered no regulatory protection, we concluded that any investor-owned companies with nuclear facilities were not directly comparable to OPG.

4. Compare the capital structures for the benchmark low risk U.S. utility sample to the capital structures for the "wires" and "high Gx" samples to determine the extent to which differences in betas among samples are due to differences in financial risk versus business risk.[164]

5. Compare the betas for the benchmark low risk U.S. utility sample to those of the "high Gx" sample as well as to the generation-only betas and DCF costs derived from the "high Gx sample.

6. Use the difference between the benchmark low risk U.S. sample beta and the "high Gx" and generation-only betas in conjunction with the market risk premium to estimate the incremental (to the benchmark return) equity return requirement for a utility of similar business risk to OPG at a 45% common equity ratio.

7. Based on capital structure theory (discussed at page I-8 and I-9), translate the incremental required return at a 45% common equity ratio into the common equity ratio which would eliminate the need for an incremental return, i.e., would equate the equity return requirement of OPG's regulated operations to the benchmark return.

[164] The betas used to estimate the generation-only beta were investment risk betas, that is, they comprise both business and financial risk. To the extent that the samples have different capital structures (and thus different levels of financial risk), business risk betas rather than the traditional investment risk betas would need to be calculated and used. By isolating the financial risk from the business risk, the incremental cost of capital arising from exposure to the business risks of generation can then be estimated.

1. Selection of Vertically Integrated Utility Sample

A sample of U.S. vertically integrated utilities with a high proportion of their assets devoted to generation was selected, comprised of all utilities satisfying the following criteria:

a. Classified by *Value Line* as an electric utility;

b. Standard & Poor's debt rating of BBB- or higher;

c. I/B/E/S long-term earnings growth forecasts available;

d. Paid a dividend in 2006; and,

e. Generation assets comprising one-third or more of total assets.

The 21 utilities that met these criteria are listed on Schedule 28. The sample has a median S&P debt rating of BBB. The average proportion of generation assets to total assets for the sample is approximately 49%, with 16 of the sample companies having nuclear generation assets. Based on 2006 production in MWs, nuclear generation accounted for approximately 10%. The "wires" operations of the high generation sample comprised approximately 44% of total assets; "other operations" accounted for approximately 7% of the total assets.

2. Betas and CAPM Cost of Equity for the High Generation Sample

The beta for the "High Gx" utility sample was estimated to be approximately 0.84 based on both the *Value Line* and Standard & Poor's adjusted betas[165] for the firms in the sample.[166]

The *Value Line* and S&P betas are as follows:

Table I-1

	Value Line	**S&P Adjusted**
Mean	0.93	0.77
Median	0.95	0.81
Asset-Weighted Average	0.93	0.68

Source: Schedule 28.

The market risk premium and risk free rate used to deriving the CAPM costs of equity were the same 6.50% and 5.0% used in the development of the benchmark return on equity. At a 0.84 beta, the CAPM cost of equity for the high generation utility sample is approximately 10.5%, compared to approximately 9.5% for the low risk utility U.S. sample used to establish the benchmark return on equity (beta of 0.71).

[165] "Raw" betas were calculated using 60 monthly observations using the S&P 500 as the market index. The betas were adjusted using the following formula: ⅔ ("raw" beta) + ⅓ (market beta of 1.0). *Value Line*, Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

[166] The 0.84 beta represents the average of the simple mean, median, and asset-weighted average betas of the sample.

3. Estimation of a Generation-Only Beta

Using the residual beta methodology, the generation-only beta was estimated from the beta of the high generation sample. The "residual beta" methodology is described in Roger Morin, *New Regulatory Finance*, Vienna, VA: Public Utilities Reports, Inc., 2006. It is based on the Capital Asset Pricing Model, which holds that the beta of a portfolio is the market value weighted average of the betas of the investments that make up the portfolio. The notion that the beta of a firm is equal to the weighted average of its divisional betas is a foundation for the "pure play" technique of estimating the betas for individual divisions of a multi-division firm. As stated in Russell J. Fuller and Halbert S. Kerr, "Estimating the Divisional Cost of Capital: An Analysis of the Pure-Play Technique," *Journal of Finance*, December 1981, "it can be shown that the beta for a multidivisional firm approximates the weighted average of its divisional betas". The pure play technique estimates the divisional betas using the betas of proxy firms. The proxy firms for each division operate in a single line of business (pure play), the same line of business as the individual divisions of the multi-division company.

The residual beta methodology is used to estimate the beta of a division for which there are no pure play proxies. The methodology entails disaggregating the beta of a multi-divisional firm into the betas of its divisions. Its application requires the beta of the firm as a whole and a "pure play" beta for each of the divisions other than the one for which there are no pure play proxies. In the disaggregation of the company beta into the divisional betas, the weights to be given to each division should be equal to their relative contribution to the operating income of the consolidated entity. For the purpose of this analysis, I have used assets as a proxy for the relative contribution of each division (or business segment) to the company as a whole. The disaggregation formula for estimating the generation-only beta is:

$$\beta_{HighGx} = \beta_{Gx} \text{ x } \%Assets_{Gx} + \beta_{Pure\ Wires} \text{ x } \%Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

The Wires beta was developed from a sample of Wires utilities. A Wires sample was selected, comprised of all U.S. utilities satisfying the following criteria:

a. classified by *Value Line* as an electric or gas distribution utility;
b. with at least 80% of total assets devoted to electricity and gas distribution operations;
c. has no more than 5% of its assets in generation;
d. whose Standard & Poor's debt rating is BBB- or higher; and,
e. has I/B/E/S forecasts.[167]

The 8 firms in the sample are found in Schedule 29. Wires assets account for 96% (average) of the total assets of the sample companies. The sample has a median S&P debt rating of A.

The beta for the "Wires" sample was estimated to be 0.72 based on both the *Value Line* and Standard & Poor's adjusted betas the firms in the sample.

[167] The existence of I/B/E/S forecasts ensures that the utilities have an analyst following, which in turn, ensures that the companies shares are traded frequently enough so that the betas are meaningful.

The *Value Line* and S&P betas are as follows:

Table I-2

	Value Line	**S&P Adjusted**
Mean	0.88	0.60
Median	0.83	0.57
Asset-Weighted Average	0.85	0.56

Source: Schedule 29.

From the "Wires" sample beta, a "pure wires" beta was estimated at 0.70, assuming a beta of 1.0 for "Other Operations" and using the following formula:

$$\beta_{Wires} = \beta_{Pure\ Wires} \ x \ Assets_{Wires} + \beta_{Other} \ x \ \%Assets_{Other}$$

Using a) the estimated beta for high generation of 0.84, b) the beta for pure wires of 0.70, c) an assumed market average beta of 1.0 for other operations and d) the proportion of assets for the "high Gx" sample devoted to generation, wires and other operations, the following equation was used to solved for the generation-only beta (β_{Gx}):

$$\beta_{HighGx} = \beta_{Gx} \ x \ Assets_{Gx} + \beta_{Pure\ Wires} \ x \ \%Assets_{Wires} + \beta_{Other} \ x \ \%Assets_{Other}$$

The derived generation-only beta is 0.94.

4. Derivation of Generation-Only CAPM Cost of Equity

The generation-only beta of 0.94 was combined with the estimates of the market risk premium and risk-free rate to arrive at an estimate of the generation-only CAPM cost of equity of approximately 11.1%.

5. Comparison of Sample Capital Structures

The capital structures for the benchmark low risk U.S. utility sample, the "wires", and the "high Gx" samples were compared to determine the extent to which differences in betas among samples are due to differences in financial risk versus business risk. Since the common equity ratio of each of the three samples was approximately 45%, any difference in betas among the samples could be attributed to business risk. The table below compares the 2006 equity ratios of the benchmark low risk utility sample, the "wires" sample and the "high Gx" sample.

Table I-3

	Benchmark	**Wires**	**High Gx**
Mean	44.9%	44.9%	44.8%
Median	44.6%	47.0%	45.8%
Weighted Average	43.5%	44.2%	43.0%

Source: Schedules 13, 28 and 29

6. Comparison of Betas

The betas of the benchmark low risk utility U.S. utility sample, the "high Gx" sample and the derived generation-only beta are respectively 0.71, 0.84 and 0.94.

7. Calculation of the Incremental Cost of Equity at a 45% Common Equity Ratio

The differences between the beta for the benchmark low risk U.S. utility sample (0.71) and those of the "high Gx" sample (0.84) and the derived generation-only beta (0.94) were determined. These differences, in conjunction with estimated market risk premium, were used to estimate the incremental cost of equity for a utility of similar risk to OPG at a 45% common equity ratio. The incremental return requirement was calculated as follows:

Incremental Return Requirement at 45% Equity = Difference in Beta x Market Risk Premium

Based on the high generation sample, the incremental equity return requirement is equal to approximately 85 basis points; based on the derived generation-only betas, the incremental equity return requirement is approximately 150 basis points, estimated as follows:

Incremental Equity Return	=	$(\beta_{HighGx} - \beta_{Benchmark\ Sample}) \times MRP$
	=	(0.84-0.71) X 6.5%
	=	0.85%

Incremental Equity Return	=	$(\beta_{Gx} - \beta_{Benchmark\ Sample}) \times MRP$
	=	(0.94-0.71) X 6.5%
	=	1.50%

8. Application of Capital Structure Theory

Based on both the high generation sample beta and the derived generation-only betas compared to the benchmark low risk utility sample beta, the incremental required equity return for OPG's regulated operations at a 45% common equity ratio – equal to the common equity ratios of the samples – is in the range of 0.85% to 1.50%. Since OPG's regulated operations are 100% generation, the focus should be on the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%. Thus, compared to the benchmark return on equity of 10.5%, which is based on the application of multiple tests, the return on equity for OPG at a 45% common equity ratio would be approximately 11.75% to 12.0%.

Using capital structure theory, the incremental required return at a 45% common equity ratio can be translated into the common equity ratio which would eliminate the need for an incremental return, i.e., would equate the return requirement of OPG's regulated operations to the benchmark return.

The estimation of the change in equity ratio for a given change in equity return is based on two different theories of the relationship between capital structure and return on equity. Theory 1 posits that income taxes and the deductibility of interest for corporate income tax purposes have no impact on the cost of capital. Under this theory, the overall cost of capital stays constant when the capital structure changes, although the costs of the debt and equity components change (i.e., the cost of equity rises when the equity ratio declines). Theory 2 posits that income taxes and the corporate deductibility of interest expense cause the overall cost of capital to continually decline as the equity ratio declines and the debt ratio increases. The underlying formulas for the two theories are contained in Schedule 31.[168]

The actual impact on the cost of capital most likely lies in between the results of the two theories; income taxes and the deductibility of interest do tend to decrease the cost of capital (as the income trust market has demonstrated), but as the debt ratio rises, there are increasing costs in terms of loss of financing flexibility and potential bankruptcy. Moreover, in the case of regulated companies, the benefit of the tax deductibility of interest is to the benefit of ratepayers, while in the unregulated sector, the benefit goes to the shareholder. Since both theories have merit, both were applied to estimate the impact of a change in return on equity on capital structure.

The table below indicates that, based on both theories, the range of common equity ratios required to equate an 11.75-12.0% return on equity for OPG's regulated operations at a 45%

[168] The inputs for the derivation of the common equity ratio required to equate the return requirement of OPG's regulated operations to the benchmark return include a cost of new long-term debt of 6.0% and a corporate income tax rate of 34%.

equity ratio to the benchmark return of 10.5% is in the range of 55-60% (mid-point of 57.5%).[169] Schedule 31 demonstrates the calculation at a 57.5% common equity ratio.

Table I-4

Return on Equity	Common Equity Ratio		
	55%	**57.5%**	**60%**
Theory 1	10.5%	10.2%	10.0%
Theory 2	11.0%	10.8%	10.6%
Average	10.75%	10.5%	10.3%

[169] At a 0% tax rate, Theories I and 2 are identical. At a 0% tax rate, the indicated common equity ratio for OPG's regulated operations required to equate OPG's return on equity to the benchmark ROE of 10.5% is 56%.

APPENDIX J

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 150 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- "Utility Cost of Capital Canada vs. U.S.", presented at the CAMPUT Conference, May 2003.

- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- "Incentive Regulation: An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

Expert Testimony/Opinions

On

Rate of Return & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005
Ameren (Central Illinois Light Company)	2005
Ameren (Illinois Power)	2004, 2005
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007

Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004
Hydro One	1999, 2001, 2006
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Platte Pipeline Co.	2002

St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

**Expert Testimony/Opinions
On
Other Issues**

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

STATISTICAL EXHIBIT
TO

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

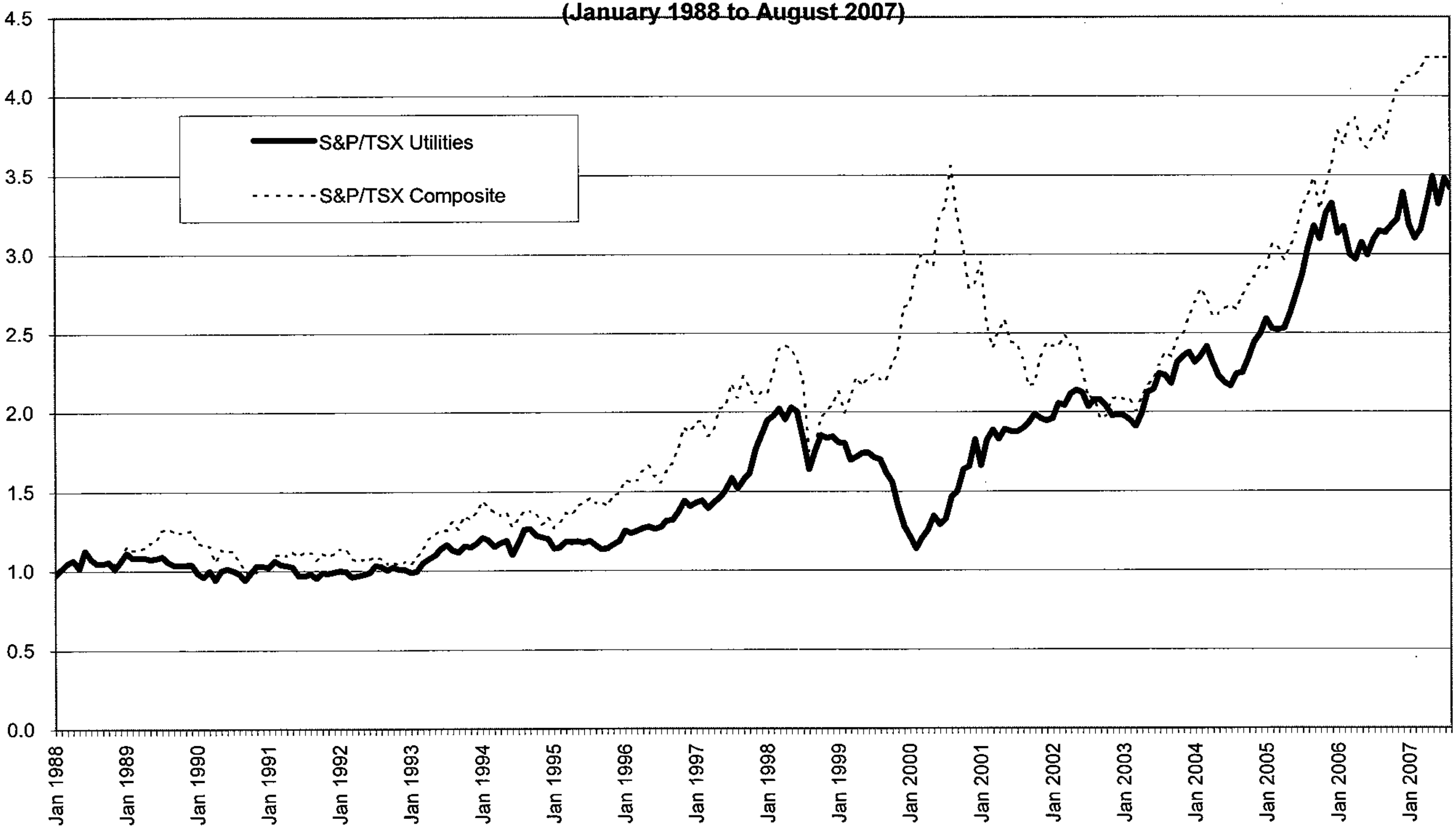
KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

November 2007

STATISTICAL EXHIBIT

TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
(January 1988 to August 2007)



TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: T-Bills Canadian	T-Bills U.S. [1]	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. [2]	Canada Bonds Over 10 Years [3]	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates	Canadian A-Rated Utility Bonds [4]	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
1993	q1	5.84	2.96	7.65	6.28	8.27	6.98	8.38	4.57	9.54	9.54	8.07	0.79
	q2	4.91	3.01	7.46	5.99	8.11	6.87	8.12	4.39	9.16	9.35	7.81	0.79
	q3	4.52	3.02	6.99	5.62	7.63	6.29	7.58	4.21	8.50	8.84	7.28	0.77
	q4	4.11	3.09	6.76	5.61	7.42	6.19	7.31	3.94	8.20	8.58	7.22	0.75
1994	q1	4.29	3.42	7.09	6.07	7.67	6.74	7.48	3.80	8.33	8.79	7.53	0.75
	q2	6.28	3.96	8.49	7.08	8.69	7.33	8.67	4.38	9.52	10.09	8.29	0.72
	q3	5.48	4.61	8.99	7.33	9.13	7.55	9.14	4.67	9.92	10.11	8.51	0.73
	q4	6.11	5.36	9.12	7.84	9.25	7.94	9.23	4.80	10.00	10.24	8.87	0.73
1995	q1	7.99	5.73	8.89	7.48	9.01	7.61	8.99	4.86	9.80	9.99	8.54	0.71
	q2	7.34	5.58	8.00	6.62	8.32	6.91	8.19	4.48	8.93	9.38	7.93	0.73
	q3	6.47	5.32	8.05	6.32	8.45	6.71	8.28	4.76	8.97	9.30	7.72	0.74
	q4	5.76	5.15	7.39	5.89	7.85	6.18	7.66	4.61	8.37	8.44	7.37	0.74
1996	q1	5.11	4.92	7.39	5.91	7.95	6.37	7.71	4.78	8.40	8.41	7.44	0.73
	q2	4.70	5.04	7.75	6.72	8.17	6.95	7.99	4.87	8.60	8.58	7.98	0.73
	q3	4.14	5.13	7.37	6.78	7.88	7.00	7.65	4.71	8.22	8.23	7.96	0.73
	q4	2.89	5.08	6.30	6.34	6.99	6.60	6.67	4.07	7.23	7.19	7.62	0.74
1997	q1	2.96	5.11	6.54	6.64	7.24	6.91	6.94	4.19	7.50	7.52	7.76	0.74
	q2	3.00	5.12	6.49	6.64	7.03	6.90	6.80	4.26	7.28	7.30	7.88	0.72
	q3	3.18	5.06	5.85	6.18	6.39	6.45	6.16	4.06	6.64	6.59	7.49	0.72
	q4	3.89	5.14	5.55	5.84	5.98	6.07	5.79	4.07	6.38	6.34	7.25	0.71
1998	q1	4.44	5.08	5.41	5.63	5.76	5.93	5.60	4.07	6.25	6.22	7.11	0.70
	q2	4.82	4.99	5.39	5.58	5.63	5.80	5.53	3.90	6.09	6.05	7.12	0.69
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	6.99	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	6.97	0.65
1999	q1	4.73	4.41	5.07	5.03	5.34	5.41	5.23	4.13	6.13	6.15	7.11	0.66
	q2	4.55	4.53	5.34	5.56	5.54	5.80	5.50	4.07	6.40	6.34	7.48	0.68
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	6.99	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	6.97	0.65
2000	q1	5.09	5.59	6.22	6.38	5.98	6.16	6.10	3.91	7.14	7.07	8.29	0.69
	q2	5.54	5.68	6.01	6.18	5.72	5.96	5.96	3.74	7.21	7.05	8.45	0.68
	q3	5.58	6.05	5.79	5.86	5.58	5.78	5.82	3.64	7.07	7.09	8.20	0.67
	q4	5.57	6.09	5.54	5.46	5.56	5.62	5.67	3.48	7.10	7.15	8.03	0.65
2001	q1	4.96	4.64	5.44	5.01	5.76	5.45	5.69	3.41	7.05	7.18	7.74	0.65
	q2	4.36	4.42	5.78	5.40	5.95	5.77	6.00	3.56	7.25	7.40	7.93	0.65
	q3	3.64	3.10	5.48	4.84	5.82	5.44	5.86	3.67	7.13	7.24	7.64	0.64
	q4	2.11	1.86	5.22	4.72	5.53	5.32	5.58	3.68	6.95	7.20	7.61	0.63
2002	q1	2.10	1.78	5.52	5.12	5.78	5.66	5.81	3.71	6.97	7.23	7.63	0.63
	q2	2.57	1.74	5.51	5.02	5.83	5.72	5.81	3.52	6.99	7.14	7.48	0.65
	q3	2.83	1.66	5.07	4.09	5.56	5.13	5.52	3.36	7.01	7.26	7.14	0.63
	q4	2.69	1.33	4.98	3.99	5.48	5.11	5.45	3.39	6.95	7.23	7.12	0.64
2003	q1	2.96	1.17	5.01	3.85	5.49	4.93	5.43	3.09	6.92	7.22	6.84	0.67
	q2	3.14	1.05	4.59	3.60	5.17	4.71	5.09	3.04	6.42	6.72	6.37	0.72
	q3	2.70	0.96	4.75	4.30	5.30	5.28	5.26	3.11	6.40	6.69	6.61	0.72
	q4	2.62	0.95	4.78	4.31	5.29	5.22	5.24	2.90	6.24	6.47	6.34	0.77
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	5.92	6.17	6.06	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.25	6.48	6.45	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.19	6.37	6.11	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	5.90	6.09	5.95	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.67	5.86	5.72	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.23	5.59	5.43	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.15	5.32	5.49	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.22	5.36	5.82	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.31	5.43	5.92	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.69	5.75	6.41	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.37	5.45	6.09	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.21	5.27	5.82	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	5.36	5.92	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.61	5.61	6.08	0.92
Annual													
	1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		11.91	12.13	9.88	0.86
	1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		10.80	11.00	9.36	0.84
	1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	9.90	10.01	8.64	0.82
	1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	8.85	9.08	7.59	0.77
	1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.44	9.81	8.30	0.73
	1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.02	9.29	7.89	0.73
	1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.11	8.38	7.75	0.73
	1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	6.95	7.19	7.60	0.72
	1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.22	6.38	7.04	0.68
	1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.64	6.92	7.62	0.67
	2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.13	7.02	8.24	0.67
	2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.09	7.25	7.73	0.65
	2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	6.98	7.22	7.35	0.64
	2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.50	6.78	6.54	0.72
	2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.06	6.28	6.14	0.77
	2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.32	5.53	5.62	0.83
	2006	4.05	4.88	4.21	4.79	4.26	4.87	4.28	1.67	5.40	5.47	6.06	0.89

[1] Rates on new issues.
[2] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3] Terms to maturity of l0 years or more.
[4] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		Government Securities											
		T-BILLS		10 Year		Long-Term		Canada Bonds Over 10 Years [3]	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates [4]	Canadian A-Rated Utility Bonds [5]	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Year		Canadian	U.S. [1]	Canadian	U.S.	Canadian	U.S. [2]						
2004	Jan	2.25	0.92	4.53	4.16	5.17	5.07	5.09	2.59	6.03	6.26	6.11	0.76
	Feb	2.12	0.96	4.36	3.99	5.05	4.95	4.94	2.52	5.87	6.13	6.08	0.75
	Mar	1.98	0.95	4.33	3.86	5.04	4.87	4.94	2.39	5.85	6.11	6.01	0.76
	Apr	1.92	0.98	4.62	4.53	5.24	5.36	5.15	2.46	6.15	6.41	6.46	0.73
	May	2.00	1.08	4.78	4.66	5.31	5.29	5.22	2.31	6.25	6.43	6.53	0.73
	June	2.01	1.33	4.83	4.62	5.33	5.41	5.30	2.37	6.36	6.60	6.36	0.75
	Jul	2.07	1.45	4.75	4.50	5.24	5.31	5.24	2.31	6.34	6.49	6.36	0.75
	Aug	2.17	1.59	4.60	4.13	5.09	4.97	5.08	2.24	6.17	6.33	6.02	0.76
	Sep	2.44	1.71	4.63	4.14	5.08	4.97	5.06	2.33	6.05	6.29	5.96	0.79
	Oct	2.57	1.91	4.47	4.05	4.94	4.87	4.91	2.26	5.99	6.17	5.89	0.82
	Nov	2.55	2.23	4.44	4.36	4.98	5.07	4.93	2.21	5.88	6.16	6.07	0.84
	Dec	2.48	2.22	4.30	4.24	4.83	4.86	4.77	2.07	5.82	5.94	5.99	0.83
2005	Jan	2.43	2.51	4.21	4.14	4.71	4.62	4.67	2.03	5.66	5.84	5.65	0.81
	Feb	2.46	2.76	4.28	4.36	4.75	4.71	4.71	2.09	5.62	5.86	5.76	0.81
	Mar	2.52	2.73	4.32	4.50	4.71	4.76	4.68	2.03	5.73	5.87	5.75	0.83
	Apr	2.45	2.90	4.14	4.21	4.58	4.53	4.54	1.90	5.04	5.79	5.54	0.80
	May	2.45	2.99	3.92	4.00	4.37	4.36	4.31	1.83	5.46	5.59	5.41	0.80
	Jun	2.48	3.13	3.74	3.94	4.21	4.19	4.20	1.85	5.20	5.40	5.35	0.82
	Jul	2.59	3.42	3.86	4.28	4.27	4.42	4.27	1.90	5.25	5.42	5.53	0.82
	Aug	2.72	3.52	3.81	4.02	4.12	4.23	4.09	1.74	5.04	5.23	5.30	0.84
	Sep	2.87	3.55	3.96	4.34	4.22	4.53	4.21	1.61	5.15	5.33	5.65	0.86
	Oct	3.06	3.98	4.17	4.57	4.35	4.73	4.36	1.66	5.34	5.49	5.91	0.85
	Nov	3.31	3.95	4.06	4.52	4.18	4.66	4.20	1.65	5.24	5.35	5.85	0.86
	Dec	3.39	4.08	3.98	4.39	4.05	4.51	4.06	1.45	5.09	5.23	5.69	0.86
2006	Jan	3.51	4.47	4.17	4.53	4.26	4.69	4.26	1.53	5.30	5.43	5.84	0.88
	Feb	3.74	4.62	4.12	4.55	4.17	4.51	4.17	1.47	5.27	5.37	5.77	0.88
	Mar	3.86	4.61	4.26	4.86	4.26	4.89	4.32	1.58	5.37	5.49	6.14	0.86
	Apr	4.04	4.65	4.51	5.07	4.52	5.17	4.57	1.72	5.67	5.70	6.37	0.89
	May	4.18	4.86	4.45	5.12	4.50	5.21	4.51	1.83	5.60	5.68	6.43	0.91
	Jun	4.30	5.01	4.58	5.15	4.61	5.19	4.63	1.88	5.81	5.86	6.43	0.90
	Jul	4.15	5.10	4.31	4.99	4.37	5.07	4.39	1.73	5.60	5.62	6.29	0.88
	Aug	4.12	5.02	4.11	4.74	4.19	4.88	4.20	1.62	5.33	5.42	6.07	0.90
	Sep	4.16	4.89	3.99	4.64	4.08	4.77	4.09	1.67	5.18	5.30	5.90	0.89
	Oct	4.17	5.08	4.02	4.61	4.08	4.72	4.10	1.69	5.33	5.28	5.84	0.89
	Nov	4.17	5.03	3.90	4.46	3.99	4.56	4.00	1.60	5.11	5.18	5.68	0.88
	Dec	4.15	5.02	4.08	4.71	4.14	4.81	4.15	1.75	5.18	5.34	5.95	0.86
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.28	5.41	6.01	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.15	5.28	5.78	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.27	5.39	5.97	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.38	5.45	5.90	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.63	5.62	6.10	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.82	5.75	6.24	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07		5.78	6.18	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14		5.76	6.17	0.95

[1] Rates on new issues.
[2] 20-year constant maturities for 1974-1976; 30-year maturities, 1976-January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3] Terms to maturity of 10 years or more.
[4] Series discontinued June 2007.
[5] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca Globe and Mail; www.federalreserve.gov
RBC Capital Markets, www.ustreas.gov

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada					United States				
		Gross Domestic Product			GDP	Consumer	Gross Domestic Product			Implicit	Consumer
		Constant	Current	Industrial	Deflator	Price	Constant	Current	Industrial	Price	Price
Year		Dollars	Dollars	Production	Index	Index	Dollars	Dollars	Production	Index	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1989		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.2	104.8	101.9	105.8	101.0	103.9	105.4
1991		98.1	104.2	93.5	106.2	110.7	101.7	109.3	99.5	107.5	109.8
1992		99.0	106.5	94.5	107.6	112.3	105.1	115.6	102.4	110.0	113.2
1993		101.3	110.6	98.8	109.2	114.4	107.9	121.4	105.8	112.5	116.5
1994		106.1	117.2	105.1	110.4	114.6	112.2	129.0	111.6	114.9	119.5
1995		109.1	122.7	109.9	112.9	117.1	115.0	134.9	117.2	117.2	122.9
1996		110.9	126.8	111.8	114.7	118.9	119.3	142.5	122.2	119.5	126.5
1997		115.6	133.5	118.0	116.1	120.8	124.7	151.4	131.1	121.5	129.5
1998		120.3	139.2	122.2	115.6	122.0	129.9	159.5	139.1	122.8	131.5
1999		127.0	149.4	129.8	117.6	124.2	135.7	169.0	145.6	124.6	134.4
2000		133.6	163.5	139.6	122.5	127.5	140.6	179.0	152.2	127.3	138.9
2001		136.0	168.5	134.6	123.9	130.8	141.7	184.7	146.9	130.4	142.8
2002		140.0	175.3	137.5	125.2	133.7	143.9	190.9	146.9	132.6	145.1
2003		142.6	184.4	137.8	129.4	137.4	147.6	199.9	148.5	135.4	148.4
2004		147.0	196.3	140.3	133.6	139.9	152.9	213.1	152.2	139.3	152.3
2005		151.5	209.1	141.6	138.1	143.0	157.6	226.7	157.1	143.8	157.5
2006		155.7	219.9	140.9	141.3	145.9	162.1	240.6	163.5	148.4	162.6
2002	1Q	138.5	170.2	135.5	122.9	131.4	142.9	188.4	144.9	131.8	143.5
	2Q	139.3	174.3	138.1	125.2	133.3	143.7	190.1	147.1	132.3	145.0
	3Q	140.5	176.7	138.5	125.7	134.7	144.5	192.0	148.0	132.8	145.6
	4Q	141.6	180.0	137.8	127.2	135.4	144.6	193.1	147.8	133.6	146.1
2003	1Q	142.2	183.8	137.4	129.3	137.2	145.0	195.2	148.7	134.6	147.6
	2Q	142.0	182.1	136.2	128.3	137.0	146.3	197.5	147.5	135.0	148.1
	3Q	142.5	185.1	137.8	129.9	137.6	148.9	202.1	148.4	135.7	148.8
	4Q	143.7	186.9	139.7	130.2	137.8	149.9	204.6	149.5	136.5	148.9
2004	1Q	144.7	190.5	139.7	131.7	138.5	151.0	208.0	150.7	137.7	150.2
	2Q	146.4	195.5	140.6	133.5	140.0	152.3	211.7	151.7	139.0	152.4
	3Q	148.0	198.4	140.9	134.2	140.3	153.7	214.8	152.4	139.8	152.9
	4Q	148.8	200.6	140.0	134.9	140.9	154.6	217.9	154.0	140.9	153.8
2005	1Q	149.4	202.9	140.0	135.8	141.4	155.8	221.6	155.7	142.2	154.8
	2Q	150.7	206.2	141.0	136.9	142.7	156.9	224.6	156.8	143.1	156.9
	3Q	152.2	211.5	142.3	138.9	144.0	158.6	229.0	157.1	144.4	158.8
	4Q	153.5	215.7	143.3	140.6	144.1	159.1	231.7	158.9	145.6	159.6
2006	1Q	154.8	217.6	142.6	140.6	144.8	161.0	236.4	160.9	146.9	160.4
	2Q	155.4	219.3	141.1	141.2	146.4	162.0	239.9	163.4	148.1	163.1
	3Q	155.9	220.8	140.7	141.7	146.5	162.4	241.9	165.1	149.0	164.1
	4Q	156.5	221.9	139.1	141.8	146.0	163.2	244.2	164.5	149.6	162.7
2007	1Q	158.0	227.5	140.2	144.1	147.4	163.5	247.1	164.9	151.2	164.3
	2Q	159.3	232.7	141.0	146.1	149.6	164.8	250.8	166.1	152.2	167.5

Note: Data are based on Chain Weighted Indexes.

Source: www.cansim2.statcan.ca , www.bea.gov , www.federalreserve.gov

HISTORIC EQUITY MARKET RISK PREMIUMS

Canada (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.4	7.0	5.5
Geometric	11.2	6.5	4.7

United States (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	13.2	6.2	6.9
Geometric	11.9	5.7	6.1

United Kingdom (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	15.0	8.7	6.3
Geometric	12.3	6.3	6.0

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006; www.statistics.gov.uk and Barclays Equity Gilt Study.

25-YEAR ROLLING AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.9%	13.7%	2.0%
1948-1972	13.8%	2.8%	14.3%	2.3%
1949-1973	13.3%	3.0%	13.5%	2.1%
1950-1974	11.3%	2.7%	11.7%	2.0%
1951-1975	10.1%	2.8%	11.9%	2.4%
1952-1976	9.6%	3.7%	11.9%	3.2%
1953-1977	10.1%	3.9%	10.8%	3.2%
1954-1978	11.2%	3.8%	11.1%	3.0%
1955-1979	11.4%	3.3%	9.8%	2.6%
1956-1980	11.5%	3.4%	9.8%	2.5%
1957-1981	10.6%	3.4%	9.4%	2.8%
1958-1982	11.6%	4.9%	10.6%	4.1%
1959-1983	11.8%	5.5%	9.8%	4.4%
1960-1984	11.5%	6.3%	9.6%	5.1%
1961-1985	12.4%	7.0%	10.8%	5.8%
1962-1986	11.5%	7.3%	10.5%	6.7%
1963-1987	12.0%	7.2%	11.1%	6.4%
1964-1988	11.8%	7.4%	10.8%	6.7%
1965-1989	11.6%	7.8%	11.4%	7.3%
1966-1990	10.8%	7.9%	10.8%	7.5%
1967-1991	11.5%	8.8%	12.4%	8.1%
1968-1992	10.8%	9.4%	11.8%	8.8%
1969-1993	11.2%	10.4%	11.7%	9.6%
1970-1994	11.2%	10.0%	12.1%	9.4%
1971-1995	11.9%	10.2%	13.5%	10.2%
1972-1996	12.7%	10.3%	13.8%	9.7%
1973-1997	12.2%	11.0%	14.4%	10.1%
1974-1998	12.2%	11.5%	16.1%	10.6%
1975-1999	14.5%	11.3%	18.0%	10.1%
1976-2000	14.0%	11.7%	16.2%	10.6%
1977-2001	13.1%	11.1%	14.7%	10.1%
1978-2002	12.2%	11.3%	14.1%	10.8%
1979-2003	12.0%	11.5%	15.0%	10.9%
1980-2004	10.8%	12.0%	14.7%	11.3%
1981-2005	10.6%	12.5%	13.6%	11.8%
1982-2006	11.7%	12.7%	14.5%	11.7%
Min	**9.6%**	**2.7%**	**9.4%**	**2.0%**
Max	**14.5%**	**12.7%**	**18.0%**	**11.8%**
Mean	**11.8%**	**7.6%**	**12.5%**	**6.8%**
Stdev.	**1.1%**	**3.5%**	**2.1%**	**3.5%**
+1 Std	**12.8%**	**11.1%**	**14.6%**	**10.3%**
-1 Std dev.	**10.7%**	**4.1%**	**10.4%**	**3.4%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(1947 Forward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.9%	13.7%	2.0%
1947-1972	13.2%	2.8%	13.9%	2.1%
1947-1973	12.8%	2.8%	12.9%	2.0%
1947-1974	11.4%	2.6%	11.5%	2.1%
1947-1975	11.6%	2.6%	12.4%	2.3%
1947-1976	11.6%	3.2%	12.7%	2.8%
1947-1977	11.6%	3.3%	12.1%	2.7%
1947-1978	12.1%	3.2%	11.9%	2.6%
1947-1979	13.1%	3.0%	12.1%	2.5%
1947-1980	13.6%	3.0%	12.7%	2.3%
1947-1981	12.9%	2.8%	12.2%	2.3%
1947-1982	12.7%	3.9%	12.5%	3.3%
1947-1983	13.4%	4.1%	12.7%	3.2%
1947-1984	12.9%	4.4%	12.6%	3.6%
1947-1985	13.3%	4.9%	13.1%	4.3%
1947-1986	13.1%	5.2%	13.2%	4.8%
1947-1987	13.0%	5.1%	13.0%	4.6%
1947-1988	12.9%	5.2%	13.1%	4.7%
1947-1989	13.1%	5.5%	13.5%	5.0%
1947-1990	12.5%	5.4%	13.2%	5.0%
1947-1991	12.5%	5.9%	13.5%	5.4%
1947-1992	12.2%	6.0%	13.4%	5.4%
1947-1993	12.6%	6.4%	13.3%	5.7%
1947-1994	12.3%	6.0%	13.1%	5.4%
1947-1995	12.4%	6.4%	13.6%	6.0%
1947-1996	12.7%	6.6%	13.8%	5.8%
1947-1997	12.7%	6.8%	14.2%	6.0%
1947-1998	12.5%	7.0%	14.4%	6.1%
1947-1999	12.8%	6.7%	14.6%	5.9%
1947-2000	12.7%	6.8%	14.1%	6.1%
1947-2001	12.3%	6.8%	13.7%	6.1%
1947-2002	11.8%	6.8%	13.0%	6.3%
1947-2003	12.1%	6.8%	13.3%	6.2%
1947-2004	12.1%	6.9%	13.2%	6.3%
1947-2005	12.3%	7.0%	13.1%	6.3%
1947-2006	12.4%	7.0%	13.2%	6.2%
Min	**11.4%**	**2.6%**	**11.5%**	**2.0%**
Max	**13.6%**	**7.0%**	**14.6%**	**6.3%**
Mean	**12.6%**	**5.1%**	**13.1%**	**4.4%**
Stdev.	**0.5%**	**1.6%**	**0.7%**	**1.6%**
+1 Std	**13.1%**	**6.7%**	**13.8%**	**6.1%**
-1 Std dev.	**12.0%**	**3.4%**	**12.4%**	**2.8%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(2006 Backward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-2006	12.4%	7.0%	13.2%	6.2%
1948-2006	12.6%	7.0%	13.3%	6.4%
1949-2006	12.6%	7.2%	13.4%	6.4%
1950-2006	12.5%	7.2%	13.3%	6.4%
1951-2006	11.8%	7.3%	13.0%	6.5%
1952-2006	11.6%	7.5%	12.8%	6.7%
1953-2006	11.8%	7.6%	12.7%	6.8%
1954-2006	12.0%	7.7%	12.9%	6.9%
1955-2006	11.5%	7.7%	12.2%	6.9%
1956-2006	11.2%	7.8%	11.8%	7.0%
1957-2006	11.1%	8.1%	11.9%	7.3%
1958-2006	11.8%	8.1%	12.4%	7.3%
1959-2006	11.4%	8.4%	11.7%	7.6%
1960-2006	11.5%	8.7%	11.7%	7.8%
1961-2006	11.7%	8.7%	12.0%	7.6%
1962-2006	11.2%	8.7%	11.6%	7.8%
1963-2006	11.7%	8.8%	12.1%	7.8%
1964-2006	11.6%	8.9%	11.8%	8.0%
1965-2006	11.2%	9.0%	11.7%	8.1%
1966-2006	11.4%	9.1%	11.7%	8.2%
1967-2006	11.8%	9.3%	12.3%	8.4%
1968-2006	11.7%	9.6%	12.0%	8.8%
1969-2006	11.4%	9.9%	12.0%	9.0%
1970-2006	11.7%	10.2%	12.5%	9.4%
1971-2006	12.1%	9.9%	12.8%	9.4%
1972-2006	12.2%	9.9%	12.7%	9.2%
1973-2006	11.8%	10.1%	12.5%	9.3%
1974-2006	12.1%	10.4%	13.4%	9.7%
1975-2006	13.3%	10.7%	14.6%	9.8%
1976-2006	13.2%	11.0%	13.9%	9.8%
1977-2006	13.2%	10.7%	13.6%	9.6%
1978-2006	13.3%	10.9%	14.3%	10.0%
1979-2006	12.7%	11.2%	14.5%	10.4%
1980-2006	11.6%	11.8%	14.4%	10.8%
1981-2006	10.8%	12.1%	13.7%	11.4%
1982-2006	11.7%	12.7%	14.5%	11.7%
Min	**10.8%**	**7.0%**	**11.6%**	**6.2%**
Max	**13.3%**	**12.7%**	**14.6%**	**11.7%**
Mean	**11.9%**	**9.2%**	**12.8%**	**8.3%**
Stdev.	**0.7%**	**1.6%**	**0.9%**	**1.5%**
+1 Std	**12.6%**	**10.8%**	**13.7%**	**9.9%**
-1 Std dev.	**11.3%**	**7.6%**	**11.9%**	**6.8%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

**FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS
FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
FOR FIVE YEAR PERIODS ENDING:**

	1997 (%)	1998 (%)	1999 (%)	2000 (%)	2001 (%)	2002 (%)	2003 (%)	2004 (%)	2005 (%)	2006 (%)	Average
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**4.70**
10 Sector Indices											
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	4.72
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	4.10
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	6.72
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	5.05
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	8.15
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	5.80
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	13.50
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	6.51
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	6.48
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	4.07
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**6.51**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**5.98**

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:											
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.62**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.68**

Source: TSX Review

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS

	Compound Returns						Betas					
	56-03	56-97	64-73	74-83	84-93	94-03	56-03	56-97	64-73	74-83	84-93	94-03
Metals/Minerals	0.08	0.08	0.07	0.11	0.07	0.07	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	0.10	0.10	0.16	0.16	0.11	-0.03	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	0.10	0.08	0.15	0.12	0.05	0.15	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	0.07	0.07	0.05	0.12	0.10	0.03	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	0.11	0.12	0.10	0.14	0.11	0.10	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	0.07	0.10	0.08	0.11	0.06	0.01	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [1/]	0.05	0.05	0.01	0.17	-0.02	0.01	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	0.10	0.11	0.13	0.18	0.03	0.09	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	0.12	0.12	0.05	0.14	0.14	0.13	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	0.11	0.11	0.03	0.18	0.11	0.16	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	0.13	0.15	0.19	0.15	0.13	0.07	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	0.10	0.11	0.11	0.12	0.09	0.07	0.78	0.86	0.93	0.84	0.83	0.46
Finance	0.12	0.13	0.12	0.12	0.12	0.18	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	0.11	0.11	0.13	0.15	0.09	0.14	0.94	1.03	1.26	0.97	1.20	0.68
Intercept							**0.18**	**0.18**	**0.12**	**0.15**	**0.14**	**0.12**
Adjusted R Square							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Data only available starting July 1961

Source: TSX Review

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS

	Compound Returns [1/]			Betas		
	88-06	88-97	97-06	88-06	88-97	97-06
Consumer Discretionary	0.086	0.102	0.078	0.787	0.904	0.731
Consumer Staples	0.135	0.127	0.178	0.348	0.727	0.165
Energy	0.129	0.084	0.167	0.656	0.765	0.580
Financials	0.160	0.183	0.170	0.784	1.039	0.677
Health Care	0.053	0.155	-0.056	0.871	0.807	0.955
Industrials	0.066	0.083	0.061	0.969	1.131	0.864
Information Technology	0.077	0.218	-0.021	1.799	1.213	2.167
Materials	0.066	0.034	0.057	0.919	1.257	0.722
Telecommunication Services	0.144	0.154	0.160	0.738	0.578	0.866
Utilities	0.116	0.115	0.140	0.232	0.624	0.052
Intercept				**0.14**	**0.14**	**0.17**
Adjusted R Square				**23%**	**1%**	**45%**
Beta				**-0.043**	**-0.017**	**-0.098**

[1/] Data only available starting December 1987

Source: TSX Review

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Consumer Discretionary	0.91	0.81	0.82	0.82	0.80	0.73	0.69	0.68	0.73	0.74	0.80	0.83	0.86
Consumer Staples	0.75	0.68	0.65	0.62	0.60	0.44	0.23	0.10	0.08	-0.08	-0.07	0.07	0.37
Energy	0.68	0.93	0.92	0.97	0.85	0.90	0.66	0.49	0.43	0.26	0.17	0.48	1.03
Financials	1.14	0.93	1.02	0.94	1.12	1.00	0.78	0.66	0.66	0.38	0.39	0.56	0.68
Health Care	0.84	0.35	0.39	0.60	1.01	1.00	1.09	0.98	0.99	0.85	0.82	0.72	0.85
Industrials	1.15	1.20	1.10	0.97	0.93	0.78	0.72	0.82	0.86	0.91	1.05	1.13	1.06
Information Technology	1.12	1.26	1.36	1.57	1.41	1.55	1.78	2.13	2.28	2.74	2.87	2.68	2.07
Materials	1.26	1.39	1.27	1.32	1.12	1.04	0.74	0.60	0.57	0.43	0.41	0.77	1.32
Telecommunication Services	0.61	0.56	0.64	0.64	0.92	1.11	0.92	0.94	0.93	0.83	0.58	0.74	0.52
Utilities	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25

Source: TSX Review

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Canadian Utilities	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32
Emera	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12
Enbridge	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22
Fortis	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48
PNG	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54
Terasen Inc [1/]	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na
TransCanada Pipelines	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25

Adjusted Betas [2/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Canadian Utilities	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54
Emera	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41
Enbridge	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48
Fortis	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65
PNG	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69
Terasen Inc	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na
TransCanada Pipelines	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50

[1/] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.

[2/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's Research Insight and TSX Review.

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Exhibit C2
Tab 1
Schedule 1
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Schedule 9

RECENT SUB-PERIOD BETAS FOR REGULATED CANADIAN UTILITIES

Including Nortel in the Market Index

"Raw" Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	-0.09	-0.07	0.08	0.33	0.42	0.52	0.72	0.46	0.55	0.36	0.45
Emera	-0.04	-0.01	0.00	0.06	0.13	0.16	0.48	0.20	0.20	0.14	0.19
Enbridge	-0.52	-0.42	-0.46	0.13	0.28	0.35	0.33	0.38	0.30	0.25	0.29
Fortis	-0.12	-0.06	0.06	0.17	0.33	0.44	0.46	0.70	0.64	0.53	0.55
PNG	0.32	0.57	0.71	0.95	0.99	0.96	0.84	0.60	0.74	0.57	0.55
Terasen Inc [1]	-0.07	-0.11	-0.06	-0.02	0.17	0.18	0.41	0.30	0.25	0.25	0.25
TransCanada Pipelines	-0.34	-0.08	-0.39	0.12	0.35	0.47	0.59	0.43	0.47	0.43	0.45
Mean	**-0.12**	**-0.03**	**-0.01**	**0.25**	**0.38**	**0.44**	**0.55**	**0.44**	**0.45**	**0.36**	**0.39**
Median	**-0.09**	**-0.07**	**0.00**	**0.13**	**0.33**	**0.44**	**0.48**	**0.43**	**0.47**	**0.36**	**0.45**
S&P/TSX Utilities	-0.30	-0.16	-0.22	0.18	0.33	0.44	0.50	0.48	0.47	0.29	0.35

Adjusted Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.27	0.28	0.38	0.55	0.61	0.68	0.81	0.64	0.70	0.57	0.63
Emera	0.31	0.32	0.33	0.37	0.42	0.43	0.65	0.47	0.46	0.42	0.46
Enbridge	-0.02	0.05	0.02	0.41	0.52	0.56	0.55	0.59	0.53	0.50	0.52
Fortis	0.25	0.29	0.37	0.44	0.55	0.62	0.64	0.80	0.76	0.69	0.70
PNG	0.55	0.72	0.80	0.96	0.99	0.98	0.89	0.73	0.82	0.71	0.70
Terasen Inc [1]	0.28	0.26	0.29	0.32	0.44	0.45	0.61	0.53	0.50	0.50	0.50
TransCanada Pipelines	0.10	0.28	0.07	0.41	0.56	0.65	0.72	0.61	0.65	0.62	0.63
Mean	**0.25**	**0.31**	**0.32**	**0.50**	**0.58**	**0.62**	**0.70**	**0.62**	**0.63**	**0.57**	**0.59**
Median	**0.27**	**0.28**	**0.33**	**0.41**	**0.55**	**0.62**	**0.65**	**0.61**	**0.65**	**0.57**	**0.63**
S&P/TSX Utilities	0.13	0.22	0.18	0.45	0.55	0.62	0.67	0.65	0.64	0.52	0.56

Excluding Nortel from the Market Index

"Raw" Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.06	0.14	0.18	0.37	0.41	0.46	0.57	0.39	0.52	0.31	0.40
Emera	0.00	0.03	0.02	0.09	0.15	0.19	0.40	0.18	0.21	0.15	0.19
Enbridge	-0.33	-0.16	-0.31	0.19	0.50	0.58	0.58	0.57	0.45	0.37	0.39
Fortis	-0.11	0.04	0.16	0.25	0.26	0.37	0.31	0.54	0.58	0.48	0.49
PNG	0.96	1.21	1.21	1.03	1.12	0.97	0.77	0.49	0.70	0.54	0.52
Terasen Inc [1]	0.13	0.06	0.04	0.04	0.37	0.37	0.55	0.47	0.39	0.38	0.38
TransCanada Pipelines	-0.29	0.10	-0.28	0.16	0.48	0.57	0.66	0.52	0.54	0.47	0.49
Mean	**0.06**	**0.21**	**0.14**	**0.31**	**0.47**	**0.50**	**0.55**	**0.45**	**0.48**	**0.39**	**0.41**
Median	**0.00**	**0.06**	**0.04**	**0.19**	**0.41**	**0.46**	**0.57**	**0.49**	**0.52**	**0.38**	**0.40**
S&P/TSX Utilities	-0.14	0.06	-0.09	0.23	0.47	0.55	0.59	0.57	0.54	0.34	0.39

Adjusted Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.37	0.43	0.45	0.58	0.61	0.64	0.71	0.59	0.68	0.54	0.60
Emera	0.33	0.35	0.34	0.39	0.43	0.46	0.60	0.45	0.47	0.43	0.46
Enbridge	0.11	0.22	0.12	0.46	0.66	0.72	0.72	0.71	0.63	0.58	0.59
Fortis	0.26	0.36	0.44	0.50	0.51	0.58	0.53	0.69	0.72	0.65	0.68
PNG	0.97	1.14	1.14	1.02	1.08	0.98	0.84	0.66	0.80	0.69	0.68
Terasen Inc [1]	0.42	0.37	0.35	0.36	0.58	0.58	0.70	0.65	0.59	0.58	0.59
TransCanada Pipelines	0.14	0.40	0.14	0.44	0.65	0.71	0.77	0.68	0.69	0.64	0.66
Mean	**0.37**	**0.47**	**0.43**	**0.53**	**0.65**	**0.67**	**0.70**	**0.63**	**0.65**	**0.59**	**0.60**
Median	**0.33**	**0.37**	**0.35**	**0.46**	**0.61**	**0.64**	**0.71**	**0.66**	**0.68**	**0.58**	**0.60**
S&P/TSX Utilities	0.23	0.37	0.27	0.49	0.64	0.70	0.73	0.71	0.69	0.56	0.59

[1] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.

Source: Standard and Poor's Research Insight and TSX Review

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1956-2006)

Average	Utilities Index Return	Bond Return	Risk Premium
Arithmetic	12.6	7.8	4.8
Geometric	11.5	7.4	4.1

United States
(1947-2006)

Average	S&P/Moody's Electric Index Return	Bond Return	Risk Premium
Arithmetic	11.4	6.2	5.2
Geometric	10.2	5.7	4.5

Average	S&P / Moody's Gas Distribution Index Return	Bond Return	Risk Premium
Arithmetic	12.4	6.2	6.2
Geometric	11.2	5.7	5.5

Note: The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2006.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2006 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2006 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports, and www.federalreserve.gov

25-YEAR ROLLING AVERAGE RETURNS FOR CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS

	Canada		U.S.		
	S&P/TSX Utilities Returns	Long Government Bond Returns	S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
1947-1971			9.7%	10.7%	2.0%
1948-1972			10.3%	11.3%	2.3%
1949-1973			9.5%	10.2%	2.1%
1950-1974			7.5%	9.0%	2.0%
1951-1975			9.3%	9.9%	2.4%
1952-1976			9.6%	11.1%	3.2%
1953-1977			9.1%	11.0%	3.2%
1954-1978			8.6%	10.8%	3.0%
1955-1979			7.7%	11.1%	2.6%
1956-1980	12.3%	3.4%	7.5%	12.0%	2.5%
1957-1981	10.9%	3.4%	8.2%	11.1%	2.8%
1958-1982	12.3%	4.9%	9.2%	11.0%	4.1%
1959-1983	11.5%	5.5%	8.2%	10.8%	4.4%
1960-1984	11.7%	6.3%	9.0%	11.4%	5.1%
1961-1985	11.6%	7.0%	9.1%	11.4%	5.8%
1962-1986	11.4%	7.3%	9.1%	11.1%	6.7%
1963-1987	12.3%	7.2%	8.8%	10.9%	6.4%
1964-1988	12.3%	7.4%	9.0%	11.3%	6.7%
1965-1989	12.2%	7.8%	9.7%	12.6%	7.3%
1966-1990	11.0%	7.9%	9.7%	12.6%	7.5%
1967-1991	11.7%	8.8%	11.1%	13.9%	8.1%
1968-1992	11.3%	9.4%	11.4%	14.3%	8.8%
1969-1993	11.4%	10.4%	11.6%	14.2%	9.6%
1970-1994	12.2%	10.0%	11.6%	14.4%	9.4%
1971-1995	11.6%	10.2%	12.4%	14.3%	10.2%
1972-1996	12.2%	10.3%	12.3%	14.7%	9.7%
1973-1997	13.4%	11.0%	13.2%	15.0%	10.1%
1974-1998	14.1%	11.5%	14.8%	15.6%	10.6%
1975-1999	13.1%	11.3%	15.2%	15.5%	10.1%
1976-2000	14.3%	11.7%	15.5%	15.6%	10.6%
1977-2001	13.4%	11.1%	14.4%	13.8%	10.1%
1978-2002	12.9%	11.3%	13.6%	13.7%	10.8%
1979-2003	13.3%	11.5%	14.5%	14.5%	10.9%
1980-2004	12.5%	12.0%	15.1%	13.6%	11.3%
1981-2005	13.1%	12.5%	15.1%	12.3%	11.8%
1982-2006	13.7%	12.7%	15.1%	13.6%	11.7%
Min	**10.9%**	**3.4%**	**7.5%**	**9.0%**	**2.0%**
Max	**14.3%**	**12.7%**	**15.5%**	**15.6%**	**11.8%**
Mean	**12.4%**	**9.0%**	**11.0%**	**12.5%**	**6.8%**
Stdev.	**0.9%**	**2.7%**	**2.6%**	**1.8%**	**3.5%**
+1 Std	**13.3%**	**11.8%**	**13.6%**	**14.3%**	**10.3%**
-1 Std dev.	**11.4%**	**6.3%**	**8.4%**	**10.7%**	**3.4%**

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports and Standard and Poor's Research Insight

CUMULATIVE AVERAGE RETURNS FOR
CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS
(Forward)

	Canada		U.S.			
	S&P/TSX Utilities Returns	Long Government Bond Returns		S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
			1947-1971	9.7%	10.7%	2.0%
			1947-1972	9.4%	10.8%	2.1%
			1947-1973	8.4%	9.7%	2.0%
			1947-1974	7.2%	9.4%	2.1%
			1947-1975	8.7%	9.9%	2.3%
			1947-1976	9.2%	11.2%	2.8%
			1947-1977	9.2%	11.2%	2.7%
			1947-1978	8.8%	10.7%	2.6%
			1947-1979	8.5%	11.5%	2.5%
1956-1980	12.3%	3.4%	1947-1980	8.5%	12.1%	2.3%
1956-1981	10.9%	3.1%	1947-1981	8.8%	11.5%	2.3%
1956-1982	12.3%	4.6%	1947-1982	9.6%	11.1%	3.3%
1956-1983	11.5%	4.8%	1947-1983	9.7%	11.7%	3.2%
1956-1984	11.7%	5.1%	1947-1984	10.1%	11.9%	3.6%
1956-1985	11.6%	5.8%	1947-1985	10.5%	12.0%	4.3%
1956-1986	11.4%	6.2%	1947-1986	10.9%	12.4%	4.8%
1956-1987	12.3%	6.0%	1947-1987	10.4%	11.9%	4.6%
1956-1988	12.3%	6.1%	1947-1988	10.6%	12.1%	4.7%
1956-1989	12.2%	6.4%	1947-1989	11.1%	12.8%	5.0%
1956-1990	11.0%	6.3%	1947-1990	10.9%	12.5%	5.0%
1956-1991	11.7%	6.8%	1947-1991	11.4%	12.7%	5.4%
1956-1992	11.3%	7.0%	1947-1992	11.3%	12.8%	5.4%
1956-1993	11.4%	7.4%	1947-1993	11.3%	12.9%	5.7%
1956-1994	12.2%	7.0%	1947-1994	10.8%	12.4%	5.4%
1956-1995	11.6%	7.5%	1947-1995	11.2%	12.7%	6.0%
1956-1996	12.2%	7.6%	1947-1996	11.0%	12.7%	5.8%
1956-1997	13.4%	7.9%	1947-1997	11.3%	12.8%	6.0%
1956-1998	14.1%	8.0%	1947-1998	11.5%	12.5%	6.1%
1956-1999	13.1%	7.7%	1947-1999	11.0%	12.3%	5.9%
1956-2000	14.3%	7.8%	1947-2000	11.8%	12.5%	6.1%
1956-2001	13.4%	7.7%	1947-2001	11.5%	12.4%	6.1%
1956-2002	12.9%	7.8%	1947-2002	11.1%	12.3%	6.3%
1956-2003	13.3%	7.8%	1947-2003	11.3%	12.4%	6.2%
1956-2004	12.5%	7.8%	1947-2004	11.3%	12.4%	6.3%
1956-2005	13.1%	7.9%	1947-2005	11.3%	12.2%	6.3%
1956-2006	13.7%	7.8%	1947-2006	11.4%	12.4%	6.2%
Min	**10.9%**	**3.1%**	**Min**	**7.2%**	**9.4%**	**2.0%**
Max	**14.3%**	**8.0%**	**Max**	**11.8%**	**12.9%**	**6.3%**
Mean	**12.4%**	**6.6%**	**Mean**	**10.3%**	**11.9%**	**4.4%**
Stdev.	**0.9%**	**1.4%**	**Stdev.**	**1.2%**	**0.9%**	**1.6%**
+1 Std	**13.3%**	**8.0%**	**+1 Std**	**11.5%**	**12.8%**	**6.0%**
-1 Std dev.	**11.4%**	**5.2%**	**-1 Std dev.**	**9.1%**	**10.9%**	**2.8%**

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports and Standard and Poor's Research Insight

CUMULATIVE AVERAGE RETURNS FOR
CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS
(2006 Backward)

	Canada		U.S.		
	S&P/TSX Utilities Returns	Long Government Bond Returns	S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
1947-2006			11.4%	12.4%	6.2%
1948-2006			11.8%	12.6%	6.4%
1949-2006			12.0%	12.7%	6.4%
1950-2006			11.8%	12.3%	6.4%
1951-2006			11.9%	12.5%	6.5%
1952-2006			11.8%	12.4%	6.7%
1953-2006			11.7%	12.4%	6.8%
1954-2006			11.7%	12.6%	6.9%
1955-2006			11.5%	12.3%	6.9%
1956-2006	12.6%	7.8%	11.5%	12.4%	7.0%
1957-2006	12.3%	8.1%	11.6%	12.4%	7.3%
1958-2006	12.5%	8.1%	11.7%	12.6%	7.3%
1959-2006	12.2%	8.4%	11.1%	12.0%	7.6%
1960-2006	12.2%	8.7%	11.2%	12.3%	7.8%
1961-2006	11.9%	8.7%	11.0%	12.1%	7.6%
1962-2006	11.9%	8.7%	10.6%	11.6%	7.8%
1963-2006	12.5%	8.8%	10.8%	12.0%	7.8%
1964-2006	12.6%	8.9%	10.8%	12.0%	8.0%
1965-2006	12.7%	9.0%	10.7%	12.0%	8.1%
1966-2006	12.2%	9.1%	10.9%	12.3%	8.2%
1967-2006	12.9%	9.3%	11.3%	13.0%	8.4%
1968-2006	12.8%	9.6%	11.6%	13.1%	8.8%
1969-2006	12.6%	9.9%	11.7%	12.9%	9.0%
1970-2006	13.3%	10.2%	12.4%	13.7%	9.4%
1971-2006	13.2%	9.9%	12.4%	13.2%	9.4%
1972-2006	13.3%	9.9%	12.7%	13.6%	9.2%
1973-2006	13.5%	10.1%	12.9%	13.6%	9.3%
1974-2006	14.3%	10.4%	13.9%	14.5%	9.7%
1975-2006	14.8%	10.7%	15.1%	14.9%	9.8%
1976-2006	14.6%	11.0%	14.0%	14.7%	9.8%
1977-2006	14.1%	10.7%	13.7%	13.5%	9.6%
1978-2006	13.9%	10.9%	13.8%	13.6%	10.0%
1979-2006	13.8%	11.2%	14.4%	14.2%	10.4%
1980-2006	13.2%	11.8%	15.0%	13.4%	10.8%
1981-2006	12.9%	12.1%	15.3%	12.7%	11.4%
1982-2006	13.7%	12.7%	15.1%	13.6%	11.7%
Min	**11.9%**	**7.8%**	**10.6%**	**11.6%**	**6.2%**
Max	**14.8%**	**12.7%**	**15.3%**	**14.9%**	**11.7%**
Mean	**13.1%**	**9.8%**	**12.3%**	**12.9%**	**8.3%**
Stdev.	**0.8%**	**1.3%**	**1.4%**	**0.8%**	**1.5%**
+1 Std	**13.9%**	**11.1%**	**13.7%**	**13.7%**	**9.9%**
-1 Std dev.	**12.2%**	**8.5%**	**10.9%**	**12.1%**	**6.8%**

Sources:

TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports, Standard and Poor's Research Insight

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK US ELECTRIC AND GAS UTILITIES
(Quarterly Averages of Monthly Data)

		Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Risk Premium
1993	q1	5.6	4.7	10.3	7.0	3.3
	q2	5.6	4.7	10.3	6.9	3.4
	q3	5.3	4.8	10.1	6.3	3.8
	q4	5.5	4.5	10.0	6.2	3.8
1994	q1	5.9	4.2	10.2	6.7	3.4
	q2	6.2	4.3	10.5	7.3	3.2
	q3	6.3	4.3	10.6	7.6	3.0
	q4	6.5	4.0	10.6	7.9	2.6
1995	q1	6.3	3.9	10.3	7.6	2.7
	q2	6.2	4.0	10.1	6.9	3.2
	q3	6.0	3.9	10.0	6.7	3.3
	q4	5.6	4.0	9.6	6.2	3.4
1996	q1	5.5	4.0	9.5	6.4	3.1
	q2	5.8	4.0	9.8	7.0	2.9
	q3	5.8	4.1	9.9	7.0	2.9
	q4	5.6	4.1	9.7	6.6	3.1
1997	q1	5.7	4.2	9.9	6.9	3.0
	q2	5.8	4.3	10.1	6.9	3.2
	q3	5.5	4.3	9.8	6.5	3.4
	q4	4.9	4.3	9.2	6.1	3.2
1998	q1	4.7	4.4	9.1	5.9	3.2
	q2	4.7	4.6	9.3	5.8	3.5
	q3	4.8	4.6	9.5	5.4	4.1
	q4	4.5	4.5	9.1	5.1	4.0
1999	q1	5.2	4.6	9.9	5.4	4.5
	q2	5.1	4.7	9.8	5.8	4.0
	q3	5.1	4.8	9.9	6.1	3.9
	q4	5.4	4.9	10.3	6.4	3.9
2000	q1	5.9	4.9	10.8	6.2	4.6
	q2	5.9	5.1	11.0	6.0	5.0
	q3	5.8	5.4	11.2	5.8	5.4
	q4	5.0	5.4	10.4	5.6	4.8
2001	q1	5.0	5.4	10.4	5.4	5.0
	q2	5.1	5.9	10.9	5.8	5.2
	q3	5.2	5.5	10.7	5.4	5.3
	q4	5.1	5.7	10.8	5.3	5.4
2002	q1	4.9	5.8	10.7	5.7	5.0
	q2	4.7	5.8	10.5	5.7	4.8
	q3	5.2	5.7	10.9	5.1	5.8
	q4	5.1	5.6	10.7	5.1	5.6
2003	q1	5.2	5.5	10.8	4.9	5.8
	q2	4.8	5.2	10.0	4.7	5.3
	q3	4.8	4.9	9.7	5.3	4.5
	q4	4.6	4.7	9.4	5.2	4.1
2004	q1	4.5	4.5	9.0	5.0	4.1
	q2	4.7	4.5	9.2	5.4	3.9
	q3	4.6	4.5	9.1	5.1	4.0
	q4	4.3	4.4	8.8	4.9	3.8
2005	q1	4.3	4.5	8.8	4.7	4.1
	q2	4.2	4.4	8.5	4.4	4.2
	q3	4.0	4.2	8.2	4.4	3.8
	q4	4.3	4.6	8.9	4.6	4.3
2006	q1	4.3	4.9	9.3	4.7	4.6
	q2	4.5	5.0	9.5	5.2	4.3
	q3	4.2	5.0	9.2	4.9	4.3
	q4	4.0	4.6	8.7	4.7	4.0
2007	q1	4.0	4.7	8.7	4.8	3.9
	q2	4.1	4.9	9.0	5.0	4.0
Means for Long Treasury Yields:						
Under 5.0		4.4	4.8	9.2	4.7	4.4
5.0-5.99		4.9	5.1	10.0	5.5	4.5
6.0-6.99		5.6	4.4	10.0	6.5	3.5
7.0 and above		6.2	4.2	10.4	7.5	2.9
Means:						
1993 - 2007Q2		5.1	4.7	9.8	5.8	4.0
1998 - 2007Q2		4.8	5.0	9.8	5.3	4.5

[1/] Dividend Yield is adjusted for I/B/E/S/ growth
Source: Standard & Poor's Research Insight, I/B/E/S and www.federalreserve.gov

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES

	Value Line									S & P		Moody's	Average
	Safety	Earnings Predictability	Financial Strength	Forecast Common Equity Ratio 2010-2012	Forecast Return On Average Common Equity 2010-2012	Dividend Payout Forecast 2010-2012	Beta	Research Insight Beta 1/	Common Equity Ratio 2006	Business Profile	Debt Rating	Debt Rating 2/	Market/ Book Ratio 1994-2006
AGL Resources	2	75	B++	50.8%	14.2%	58.1%	0.95	0.58	42.7%	4	A-	A3	1.76
Consol. Edison	1	85	A++	50.5%	9.1%	70.6%	0.75	0.43	47.0%	2	A	A2	1.49
FPL Group	1	80	A+	51.0%	12.4%	51.8%	0.85	0.69	44.6%	5	A	A2	1.89
Integrys Energy	2	70	B++	49.5%	11.1%	65.7%	0.85	0.66	42.4%	5	A-	A3	1.62
New Jersey Resources	1	95	A	69.3%	10.7%	54.6%	0.80	0.39	50.2%	2	A+	na	2.19
NICOR Inc.	3	75	A	69.0%	13.2%	63.5%	1.30	0.99	50.7%	3	AA	A3	2.28
Northwest Nat. Gas	1	80	A	52.0%	11.6%	60.0%	0.75	0.44	48.1%	1	AA-	A3	1.56
NSTAR	1	95	A	55.5%	15.7%	58.3%	0.80	0.64	34.4%	1	A+	A2	1.74
Piedmont Natural Gas	2	80	B++	52.8%	11.2%	71.9%	0.80	0.60	47.0%	2	A	A3	2.00
SCANA Corp.	2	95	A	49.0%	11.1%	61.5%	0.85	0.70	43.4%	4	A-	A3	1.64
Southern Co.	1	95	A	44.0%	13.0%	74.0%	0.70	0.33	40.6%	4	A	A3	2.08
Vectren Corp.	2	70	A	51.0%	10.5%	71.5%	0.95	0.71	40.6%	4	A-	Baa1	1.91
WGL Holdings Inc.	1	65	A	64.5%	11.1%	63.3%	0.85	0.54	52.2%	3	AA-	A2	1.71
Mean	**2**	**82**	**A**	**54.5%**	**11.9%**	**63.4%**	**0.86**	**0.59**	**44.9%**	**3**	**A**	**A2**	**1.84**
Median	**1**	**80**	**A**	**51.0%**	**11.2%**	**63.3%**	**0.85**	**0.60**	**44.6%**	**3**	**A**	**A3**	**1.76**
Weighted Average	**1**	**86**	**A**	**50.0%**	**12.0%**	**64.6%**	**0.80**	**0.53**	**43.5%**	**4**	**A**	**A2**	**1.84**

1/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

2/ Rating for WGL Holdings is Washington Gas Light.

Source: Standard and Poor's Research Insight, Value Line (June 2007), www.Moodys.com,
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest To Weakest* (July 24, 2007) and

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Closing Prices 7/15-8/15/2007 (2)	Expected Dividend Yield [1/] (3)	I/B/E/S Long-Term EPS Forecasts (4)	DCF Cost of Equity [2/] (5)
AGL Resources	1.64	38.77	4.4	4.5	8.9
Consolidated Edison	2.32	45.41	5.3	3.5	8.7
FPL	1.64	59.01	3.0	9.1	12.2
Integrys Energy	2.64	50.78	5.5	5.3	10.8
New Jersey Resources	1.52	48.91	3.2	4.5	7.7
Nicor Inc.	1.86	41.20	4.7	4.6	9.3
Northwest Nat. Gas	1.42	44.12	3.4	4.8	8.2
NSTAR	1.30	32.21	4.3	6.3	10.5
Piedmont Natural Gas	1.00	24.64	4.2	4.5	8.7
Scana	1.76	38.11	4.8	4.5	9.3
Southern Co.	1.61	34.87	4.8	4.6	9.4
Vectren	1.26	26.45	5.0	4.3	9.3
WGL Holdings Inc.	1.37	31.65	4.5	3.3	7.8
Mean	**1.64**	**39.70**	**4.4**	**4.9**	**9.3**
Median	**1.61**	**38.77**	**4.5**	**4.5**	**9.3**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (July 2007)

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (TWO STAGE MODEL)

Company	Annualized Last Paid Dividend (1)	Average Daily Closing Prices 7/15-8/15/2007 (2)	I/B/E/S Long-Term EPS Forecasts (3)	Stage 2 GDP Growth 1/ (4)	DCF Cost of Equity 2/ (5)
AGL Resources	1.64	38.77	4.5	5.1	9.3
Consolidated Edison	2.32	45.41	3.5	5.1	10.0
FPL	1.64	59.01	9.1	5.1	8.4
Integrys Energy	2.64	50.78	5.3	5.1	10.6
New Jersey Resources	1.52	48.91	4.5	5.1	8.1
Nicor Inc.	1.86	41.20	4.6	5.1	9.7
Northwest Nat. Gas	1.42	44.12	4.8	5.1	8.3
NSTAR	1.30	32.21	6.3	5.1	9.5
Piedmont Natural Gas	1.00	24.64	4.5	5.1	9.2
Scana	1.76	38.11	4.5	5.1	9.8
Southern Co.	1.61	34.87	4.6	5.1	9.8
Vectren	1.26	26.45	4.3	5.1	9.9
WGL Holdings Inc.	1.37	31.65	3.3	5.1	9.2
Mean	**1.64**	**39.70**	**4.9**	**5.1**	**9.4**
Median	**1.61**	**38.77**	**4.5**	**5.1**	**9.5**

1/ Consensus forecast nominal rate of GDP growth, 2009-18

2/ Internal Rate of Return: I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard and Poor's Research Insight, Yahoo.com, Blue Chip *Economic Indicators* (March 2007) and I/B/E/S (July 2007)

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RISK MEASURES FOR 20 LOW RISK CANADIAN INDUSTRIALS

Company Name	Debt Ratings S&P	Debt Ratings DBRS	CBS Stock Rating	Beta 2002-2006 Raw	Beta 2002-2006 Adjusted	2006 Equity Ratio Based On Total Capital
ANDREW PELLER LTD			Average	0.43	0.62	48.4%
ARBOR MEMORIAL SERVICES-CL B			Conservative	0.26	0.50	67.4%
ASTRAL MEDIA INC -CL A			Conservative	0.88	0.92	100.0%
CANADA BREAD CO LTD			Conservative	0.44	0.63	85.8%
CANADIAN TIRE CORP -CL A	BBB+	A(low)	Very Conservative	0.69	0.79	70.4%
FINNING INTERNATIONAL INC	BBB+	BBB(high)	Conservative	0.65	0.76	57.7%
JEAN COUTU GROUP			Very Conservative	0.30	0.53	99.6%
LEON'S FURNITURE LTD			Average	0.29	0.53	99.8%
LINAMAR CORP			Average	0.88	0.92	72.9%
LOBLAW COMPANIES LTD	BBB+	A(low)	Very Conservative	0.35	0.57	52.7%
MAGNA INTERNATIONAL -CL A	A	A	Conservative	0.93	0.95	90.3%
MAPLE LEAF FOODS INC			Very Conservative	0.31	0.54	43.8%
METRO INC -CL A	BBB	BBB	Very Conservative	0.82	0.88	60.5%
REITMANS (CANADA) -CL A			Average	0.31	0.54	96.4%
THOMSON CORP	A-	A(low)	Very Conservative	0.50	0.66	70.3%
TORSTAR CORP -CL B		BBB	Very Conservative	0.26	0.50	54.6%
TRANSCONTINENTAL INC -CL A	BBB	BBB(high)	Very Conservative	0.51	0.67	70.6%
TVA GROUP INC -CL B			Average	0.72	0.82	65.3%
UNI-SELECT INC			Average	0.33	0.55	76.2%
WESTON (GEORGE) LTD	BBB	BBB(high)	Very Conservative	0.35	0.57	33.7%
Mean	**BBB+**	**BBB(high)**	**Conservative**	**0.51**	**0.67**	**70.8%**
Median	**BBB+**	**BBB(high)**	**Conservative**	**0.44**	**0.62**	**70.3%**

Source: Standard and Poor's Research Insight, DBRS and The Blue Book of CBS Stock Reports.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
20 LOW RISK CANADIAN INDUSTRIALS

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
ANDREW PELLER LTD	10.0	12.3	13.8	13.1	10.3	18.7	6.2	7.9	9.8	12.4	10.1	6.9	10.2	11.0
ARBOR MEMORIAL SERVICES-CL B	8.1	7.1	7.3	7.5	7.6	2.2	7.5	5.1	14.5	19.7	13.0	10.6	10.5	9.2
ASTRAL MEDIA INC -CL A	7.0	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	6.3
CANADA BREAD CO LTD	14.5	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	10.5
CANADIAN TIRE CORP -CL A	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	10.9
FINNING INTERNATIONAL INC	14.9	16.3	16.0	16.2	0.5	8.7	10.5	14.1	15.5	14.0	10.1	12.0	13.4	12.4
JEAN COUTU GROUP	17.0	15.2	16.2	15.3	15.5	15.7	14.9	15.7	16.6	16.2	8.9	6.6	8.1	14.5
LEON'S FURNITURE LTD	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	17.0
LINAMAR CORP	27.7	22.3	29.0	36.9	21.9	14.7	15.7	7.8	9.7	6.5	14.0	13.6	12.3	18.3
LOBLAW COMPANIES LTD	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	15.4
MAGNA INTERNATIONAL -CL A	21.7	21.8	15.8	21.6	12.3	12.0	15.9	14.7	11.8	9.5	13.3	10.5	7.7	15.1
MAPLE LEAF FOODS INC	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	8.3
METRO INC -CL A	16.2	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	21.6
REITMANS (CANADA) -CL A	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	13.2
THOMSON CORP	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	14.2
TORSTAR CORP -CL B	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3
TRANSCONTINENTAL INC -CL A	8.1	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	11.1
TVA GROUP INC -CL B	0.3	9.2	10.4	15.0	20.5	19.8	16.4	-49.5	27.0	23.7	20.9	12.9	-1.7	10.6
UNI-SELECT INC	24.7	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	18.8
WESTON (GEORGE) LTD	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	16.9
Mean	**12.3**	**12.5**	**12.5**	**16.7**	**13.3**	**14.0**	**12.8**	**8.0**	**15.3**	**14.8**	**14.4**	**13.3**	**9.9**	**13.3**
Median	**11.2**	**12.7**	**14.0**	**14.9**	**12.6**	**13.8**	**14.3**	**10.9**	**15.0**	**15.8**	**13.8**	**13.3**	**10.8**	**12.8**
Average of Annual Medians														**13.3**

Source: Standard and Poor's Research Insight.

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety	Value Line Beta	Research Insight "Raw" Beta	Research Insight Adjusted Beta	2006 Equity Ratio Based on Total Capital
AARON RENTS INC		3	0.75	0.30	0.53	82.4%
ABM INDUSTRIES INC		3	0.85	0.81	0.87	100.0%
ALAMO GROUP INC		3	0.60	0.72	0.81	68.9%
ALBANY INTL CORP -CL A		3	1.10	0.87	0.91	56.9%
ALBERTO-CULVER CO	BBB-	1	nmf	0.16	0.43	91.9%
ALEXANDER & BALDWIN INC	A-	3	1.00	0.84	0.89	69.9%
ALICO INC		3	0.75	0.35	0.57	68.8%
ANDERSONS INC		3	0.65	0.31	0.54	51.3%
APOGEE ENTERPRISES INC		3	1.30	0.88	0.92	86.9%
APPLEBEES INTL INC		3	0.80	0.67	0.78	73.5%
APPLIED INDUSTRIAL TECH INC		3	1.20	0.64	0.76	84.5%
ARCHER-DANIELS-MIDLAND CO	A	3	0.90	0.81	0.87	67.7%
AVERY DENNISON CORP	BBB+	2	0.95	0.48	0.65	63.5%
BADGER METER INC		3	0.85	0.56	0.71	75.8%
BARNES GROUP INC		3	0.95	0.64	0.76	54.9%
BELO CORP -SER A COM	BBB-	3	0.95	0.73	0.82	54.3%
BLACK & DECKER CORP	BBB	3	1.05	0.67	0.78	42.4%
BLOCK H & R INC	BBB+	3	1.20	0.15	0.43	39.2%
BOB EVANS FARMS		3	0.90	0.68	0.79	77.4%
BOEING CO	A+	2	1.00	0.73	0.82	33.2%
BRINKS CO	BBB+	3	1.10	0.67	0.78	81.6%
BROWN-FORMAN -CL B	A	1	0.75	0.33	0.55	57.2%
BRUNSWICK CORP	BBB+	3	1.10	0.90	0.94	72.0%
BURLINGTON NORTHERN SANTA FE	BBB	2	1.00	0.83	0.89	58.5%
CARLISLE COS INC	BBB	2	1.05	0.75	0.83	68.8%
CASEYS GENERAL STORES INC		3	1.10	0.85	0.90	69.8%
CATO CORP -CL A		3	1.20	0.59	0.73	100.0%
CHURCHILL DOWNS INC		3	0.80	0.52	0.68	96.3%
CIRCUIT CITY STORES INC		3	1.30	0.43	0.62	96.9%
CLARCOR INC		2	1.05	0.64	0.76	97.1%
COACHMEN INDUSTRIES INC		3	1.35	0.79	0.86	89.7%
CONAGRA FOODS INC	BBB+	2	0.75	0.41	0.60	57.0%
CON-WAY INC	BBB	3	1.00	0.34	0.56	51.7%
COURIER CORP		3	0.90	0.88	0.92	91.3%
CSX CORP	BBB-	3	1.05	0.98	0.98	60.0%
CUBIC CORP		3	1.30	0.96	0.98	85.6%
CURTISS-WRIGHT CORP		3	0.95	0.22	0.48	67.6%
DANAHER CORP	A+	2	0.95	0.68	0.78	73.2%
DARDEN RESTAURANTS INC	BBB+	3	0.85	0.42	0.61	60.9%
DEB SHOPS INC		3	0.80	0.36	0.57	100.0%
DONALDSON CO INC		2	0.90	0.94	0.96	75.2%
DONNELLEY (R R) & SONS CO	BBB+	2	0.95	0.70	0.80	63.4%
ENNIS INC		3	0.85	0.51	0.67	77.9%
ETHAN ALLEN INTERIORS INC	BBB+	3	1.05	0.94	0.96	67.3%
EW SCRIPPS -CL A	A	2	0.85	0.48	0.65	77.1%
EXPEDITORS INTL WASH INC		3	0.80	0.44	0.62	100.0%
FAMILY DOLLAR STORES		3	1.00	0.71	0.80	82.9%
FARMER BROS CO		3	0.60	0.10	0.40	100.0%
FASTENAL CO		3	1.25	0.70	0.80	100.0%
FLEXSTEEL INDUSTRIES INC		3	0.40	0.61	0.74	77.4%

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

		Value Line		Research Insight		
Company Name	S&P Debt Rating	Safety	Beta	"Raw" Beta	Adjusted Beta	2006 Equity Ratio Based on Total Capital
FLUOR CORP	A-	3	1.20	0.98	0.99	75.6%
FORTUNE BRANDS INC	BBB	1	0.80	0.66	0.77	44.7%
FRANKLIN ELECTRIC CO INC		3	1.00	0.70	0.80	84.7%
FREDS INC		3	1.20	0.91	0.94	99.2%
FRISCH'S RESTAURANTS INC		3	0.60	0.42	0.61	81.2%
G&K SERVICES INC -CL A		3	1.10	0.48	0.65	71.9%
GANNETT CO	A-	1	0.80	0.36	0.57	61.7%
GENERAL DYNAMICS CORP	A	1	1.00	0.68	0.78	77.9%
GENERAL ELECTRIC CO	AAA	1	1.10	0.82	0.88	20.6%
GENUINE PARTS CO		1	0.80	0.69	0.79	83.6%
GORMAN-RUPP CO		3	1.05	0.81	0.87	100.0%
GRAINGER (W W) INC	AA+	2	1.10	0.76	0.84	99.6%
HARTE HANKS INC		1	0.85	0.35	0.57	70.7%
HAVERTY FURNITURE		3	1.20	0.80	0.87	85.3%
HEICO CORP		3	0.85	0.58	0.72	85.2%
HNI CORP		2	0.90	0.64	0.76	61.4%
HORMEL FOODS CORP	A	1	0.75	0.37	0.57	83.7%
HUBBELL INC -CL B	A+	2	1.10	0.99	0.99	82.2%
ILLINOIS TOOL WORKS	AA	1	1.00	0.88	0.92	86.4%
INTERPOOL INC		3	0.80	1.00	1.00	28.0%
INTL SPEEDWAY CORP -CL A	BBB	3	0.65	0.14	0.43	75.8%
JOHNSON CONTROLS INC	A-	2	1.05	0.73	0.82	60.8%
KAMAN CORP	BBB-	3	1.25	0.31	0.54	79.9%
KELLY SERVICES INC -CL A		3	1.20	0.81	0.87	91.7%
KENNAMETAL INC	BBB	3	1.20	0.96	0.97	75.9%
KIMBERLY-CLARK CORP	A+	1	0.70	0.40	0.60	62.9%
LANCASTER COLONY CORP		1	0.80	0.16	0.44	97.9%
LANCE INC		3	0.85	0.60	0.73	81.6%
LAWSON PRODUCTS		3	1.05	0.65	0.76	99.7%
LA-Z-BOY INC		3	1.20	0.90	0.93	76.5%
LEE ENTERPRISES INC		2	0.80	0.61	0.74	39.1%
LEGGETT & PLATT INC	A	2	1.00	0.95	0.97	66.9%
LENNAR CORP	BBB	3	1.30	0.47	0.65	60.2%
LIMITED BRANDS INC	BBB-	3	1.15	0.93	0.95	63.9%
LINCOLN ELECTRIC HLDGS INC		2	1.10	0.98	0.99	84.1%
LINDSAY CORP		3	1.05	0.67	0.78	80.1%
LIZ CLAIBORNE INC	BBB	1	0.95	0.79	0.86	78.2%
LOCKHEED MARTIN CORP	A-	1	0.85	-0.21	0.19	60.8%
LONGS DRUG STORES CORP		3	0.80	0.60	0.73	85.8%
LOWE'S COMPANIES INC	A+	2	1.00	0.77	0.84	78.0%
LSI INDUSTRIES INC		3	1.25	0.71	0.80	90.9%
MARCUS CORP		3	1.05	0.54	0.69	55.5%
MASCO CORP	BBB+	2	1.10	0.91	0.94	47.3%
MATTEL INC	BBB-	3	0.75	0.68	0.78	77.7%
MATTHEWS INTL CORP -CL A		3	0.95	0.32	0.54	72.5%
MCCORMICK & COMPANY INC	A	2	0.55	0.46	0.64	58.9%
MDC HOLDINGS INC	BBB-	3	1.40	0.77	0.84	65.7%
MEDIA GENERAL -CL A		3	0.90	0.74	0.83	50.6%
MEREDITH CORP		1	0.75	0.46	0.64	55.3%
MET-PRO CORP		2	0.65	0.51	0.67	90.8%
MINE SAFETY APPLIANCES CO		3	1.00	0.44	0.63	78.6%
MOLSON COORS BREWING CO	BBB	3	nmf	0.94	0.96	73.2%
MOVADO GROUP INC		3	0.95	0.92	0.95	82.5%
NATIONAL PRESTO INDS INC		3	0.85	0.72	0.81	100.0%
NEW YORK TIMES CO -CL A	BBB	2	0.85	0.61	0.74	36.2%
NEWELL RUBBERMAID INC	BBB+	3	1.00	0.72	0.81	45.7%

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety	Value Line Beta	Research Insight "Raw" Beta	Research Insight Adjusted Beta	2006 Equity Ratio Based on Total Capital
NIKE INC -CL B	A+	1	0.90	0.57	0.71	92.8%
NORDSON CORP		3	1.15	0.85	0.90	77.2%
NORFOLK SOUTHERN CORP	BBB+	3	1.05	0.74	0.82	58.8%
NORTHROP GRUMMAN CORP	BBB+	2	0.80	0.08	0.38	78.6%
OIL DRI CORP AMERICA		3	0.55	0.74	0.83	67.5%
PENTAIR INC	BBB	3	1.10	0.84	0.89	69.2%
PEPSIAMERICAS INC	A	3	0.70	0.53	0.68	48.5%
PULTE HOMES INC	BBB	3	1.50	0.95	0.97	60.0%
RAVEN INDUSTRIES INC		3	1.00	0.80	0.86	100.0%
RAYTHEON CO	BBB+	2	0.95	0.79	0.86	73.7%
ROBBINS & MYERS INC		3	1.10	0.72	0.81	76.2%
ROLLINS INC		3	0.90	0.36	0.57	99.7%
RUBY TUESDAY INC		3	0.95	0.61	0.74	46.1%
RUDDICK CORP		3	1.00	0.80	0.87	73.0%
RYDER SYSTEM INC	BBB+	3	1.05	0.57	0.71	37.9%
SCHAWK INC -CL A		3	0.60	0.33	0.55	65.3%
SHERWIN-WILLIAMS CO	A-	2	1.05	0.92	0.95	69.5%
SKYLINE CORP		3	0.95	0.68	0.78	100.0%
SMITH (A O) CORP		3	0.85	0.42	0.61	60.9%
SMUCKER (JM) CO		2	0.75	0.24	0.49	80.8%
SOUTHWEST AIRLINES	A	3	1.05	0.93	0.95	79.2%
SPARTAN MOTORS INC		3	0.80	-0.39	0.07	80.0%
STANDEX INTERNATIONAL CORP		3	1.10	0.84	0.89	63.0%
STANLEY WORKS	A	3	1.00	0.93	0.95	60.8%
SUPERIOR INDUSTRIES INTL		3	1.05	0.35	0.57	100.0%
SUPERIOR UNIFORM GROUP INC		3	0.65	0.25	0.50	94.8%
TELEFLEX INC		2	1.00	0.84	0.89	69.6%
TENNANT CO		3	1.00	0.88	0.92	98.4%
TOOTSIE ROLL INDUSTRIES INC		1	0.80	0.73	0.82	98.8%
TORO CO	BBB-	3	1.00	0.70	0.80	69.1%
TREDEGAR CORP		3	1.00	0.62	0.74	89.2%
TWIN DISC INC		3	0.75	0.63	0.75	67.9%
TYSON FOODS INC -CL A	BBB-	3	0.80	0.51	0.67	52.7%
UNIFIRST CORP		3	0.90	0.01	0.34	68.2%
UNION PACIFIC CORP	BBB	1	0.95	0.69	0.79	69.3%
UNITED INDUSTRIAL CORP		3	0.75	0.84	0.90	34.0%
UNITED PARCEL SERVICE INC	AAA	1	0.75	0.42	0.61	79.0%
UNITED TECHNOLOGIES CORP	A	1	1.10	0.65	0.76	68.6%
UNIVERSAL CORP/VA	BBB-	2	0.80	0.65	0.77	47.4%
VF CORP	A-	2	1.00	0.70	0.80	80.5%
WALGREEN CO	A+	1	0.75	0.39	0.59	94.3%
WAL-MART STORES INC	AA	1	0.80	0.57	0.71	61.2%
WASHINGTON POST -CL B	A+	1	0.75	0.31	0.54	88.3%
WASTE MANAGEMENT INC	BBB	2	0.90	0.85	0.90	42.8%
WATTS WATER TECHNOLOGIES INC	BBB	3	1.15	0.67	0.78	64.0%
WEIS MARKETS INC		1	0.85	0.37	0.58	100.0%
WERNER ENTERPRISES INC		3	1.05	0.85	0.90	89.7%
WEYCO GROUP INC		3	0.80	-0.17	0.21	93.1%
WILEY (JOHN) & SONS -CL A		3	0.70	0.37	0.58	34.6%
WOLVERINE WORLD WIDE		3	0.95	0.90	0.93	95.9%
WOODWARD GOVERNOR CO		3	0.80	0.93	0.96	86.7%
Mean	**A-**	**3**	**0.95**	**0.62**	**0.75**	**73.4%**
Median	**BBB+**	**3**	**0.95**	**0.67**	**0.78**	**75.6%**

Source: Standard & Poor's Research Insight and Value Line

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
157 LOW RISK US INDUSTRIALS

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2005
AARON RENTS INC	15.6	11.2	15.5	16.4	15.1	14.5	13.9	5.8	11.0	12.1	15.1	14.3	15.1	13.5
ABM INDUSTRIES INC	12.5	13.3	13.9	14.8	15.4	15.2	14.8	9.6	12.5	21.8	6.9	12.6	18.3	14.0
ALAMO GROUP INC	20.0	16.5	9.3	13.4	3.9	5.7	9.7	9.1	5.1	5.9	8.8	7.0	6.7	9.3
ALBANY INTL CORP -CL A	9.3	15.0	15.4	14.6	9.7	9.4	11.7	10.4	15.3	11.3	1.9	12.8	10.8	11.4
ALBERTO-CULVER CO	14.1	15.1	15.8	18.5	16.1	15.6	17.1	16.1	17.2	16.9	11.9	14.8	12.6	15.5
ALEXANDER & BALDWIN INC	12.2	8.7	9.8	11.6	4.4	9.2	11.5	15.8	8.1	10.6	11.8	13.1	12.0	10.7
ALICO INC	12.0	12.5	5.8	13.5	7.6	4.5	14.5	14.9	6.7	10.6	13.1	4.2	4.5	9.6
ANDERSONS INC	25.4	15.5	9.2	5.6	12.6	10.0	11.5	9.8	10.7	10.6	15.3	17.8	16.9	13.2
APOGEE ENTERPRISES INC	10.9	13.5	16.9	-36.2	21.0	9.1	10.5	16.4	17.1	-3.2	9.6	12.6	14.6	8.7
APPLEBEES INTL INC	19.2	18.3	16.9	16.9	17.3	19.7	23.6	21.6	23.1	22.0	23.2	22.4	18.0	20.2
APPLIED INDUSTRIAL TECH INC	8.9	10.7	13.2	13.7	12.0	6.8	10.5	9.2	4.8	6.5	9.7	15.1	17.9	10.7
ARCHER-DANIELS-MIDLAND CO	9.8	14.6	11.6	6.2	6.4	4.4	4.9	6.2	7.8	6.5	6.7	12.9	14.4	8.6
AVERY DENNISON CORP	15.1	18.6	21.4	24.5	26.7	26.2	34.6	27.7	25.9	22.6	19.5	14.8	23.0	23.1
BADGER METER INC	11.6	12.1	14.9	16.7	18.5	21.4	16.1	7.8	16.0	14.7	16.2	19.3	10.4	15.0
BARNES GROUP INC	20.4	23.3	22.8	23.9	18.7	15.5	18.7	9.6	13.3	12.5	10.1	16.5	16.1	17.0
BELO CORP -SER A COM	18.9	17.3	23.1	9.8	5.0	13.5	11.0	-0.2	9.6	8.6	8.3	8.1	8.5	10.9
BLACK & DECKER CORP	12.1	21.2	15.2	13.3	-63.8	43.7	37.8	15.0	34.0	40.5	37.9	35.3	36.2	21.4
BLOCK H & R INC	15.4	20.5	4.7	33.5	17.9	22.1	23.1	34.2	38.2	39.6	32.4	23.9	-24.3	21.6
BOB EVANS FARMS	14.4	7.3	8.7	10.4	12.4	11.8	11.5	13.8	13.9	12.1	5.8	8.1	8.6	10.7
BOEING CO	9.2	4.0	10.5	-1.5	8.9	19.4	18.9	25.9	25.0	9.1	19.3	22.9	28.0	15.4
BRINKS CO	14.0	21.5	20.9	21.2	18.8	8.6	-33.3	3.3	5.8	6.7	20.8	19.6	73.8	15.5
BROWN-FORMAN -CL B	30.1	27.5	25.1	24.2	23.5	22.2	20.9	18.3	22.8	26.8	25.7	22.3	24.8	24.1
BRUNSWICK CORP	15.0	13.0	16.6	12.0	14.2	2.9	-8.1	7.8	9.4	11.2	17.8	20.9	7.0	10.7
BURLINGTON NORTHERN SANTA FE	23.2	5.1	16.1	13.8	15.8	14.3	12.5	9.6	9.6	9.5	8.9	16.3	19.0	13.4
CARLISLE COS INC	15.2	16.9	19.2	21.5	22.5	21.6	18.7	4.6	13.2	15.0	12.0	14.9	25.8	17.0
CASEYS GENERAL STORES INC	13.5	13.9	12.3	13.5	14.2	12.9	10.8	8.9	10.2	8.6	8.1	12.4	11.3	11.6
CATO CORP -CL A	13.5	8.3	4.7	11.2	14.5	18.7	19.7	19.5	18.2	13.5	17.2	19.9	19.9	15.3
CHURCHILL DOWNS INC	15.6	14.0	17.1	18.1	17.7	14.7	11.3	10.5	9.3	9.6	3.6	28.5	8.9	13.8
CIRCUIT CITY STORES INC	21.1	18.5	10.6	7.1	8.5	10.2	6.9	7.9	4.3	-3.9	2.9	7.0	-0.5	7.7
CLARCOR INC	18.6	17.7	18.0	17.0	17.9	17.8	17.8	16.2	15.8	15.9	16.0	16.8	16.2	17.1
COACHMEN INDUSTRIES INC	21.8	21.2	21.1	13.8	16.7	14.1	1.0	-1.9	4.8	3.5	7.0	-12.6	-18.0	7.1
CONAGRA FOODS INC	20.0	7.6	26.0	23.9	12.6	13.2	19.9	18.9	17.3	17.5	13.3	11.2	16.6	16.8
CON-WAY INC	6.4	6.7	3.1	19.4	18.2	20.9	12.8	-48.8	14.9	11.8	-16.8	27.5	33.8	8.4
COURIER CORP	13.0	15.3	6.7	10.7	16.9	15.6	17.0	17.8	18.4	19.0	16.4	15.2	16.8	15.3
CSX CORP	18.9	15.5	18.5	14.9	9.2	0.9	9.6	4.8	7.6	3.0	5.1	15.5	15.5	10.7
CUBIC CORP	1.5	3.4	6.8	7.1	0.5	7.9	0.4	11.4	14.6	15.6	13.3	3.9	7.8	7.2
CURTISS-WRIGHT CORP	12.9	11.0	9.1	14.4	13.4	16.0	15.0	19.6	11.9	11.7	12.3	12.4	11.5	13.2
DANAHER CORP	19.4	20.4	30.0	18.0	16.1	17.1	17.8	14.3	17.7	16.1	18.0	18.5	19.1	18.7
DARDEN RESTAURANTS INC	4.1	6.2	-7.9	9.7	14.2	18.4	19.7	22.0	20.0	19.2	23.7	27.0	17.3	14.9
DEB SHOPS INC	-2.8	-5.1	-5.1	8.7	18.1	23.6	19.6	15.9	15.1	7.0	9.6	15.7	15.4	10.5
DONALDSON CO INC	17.6	18.8	19.3	21.4	22.8	24.1	25.9	25.2	24.8	23.0	21.3	20.6	24.7	22.3

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
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Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
DONNELLEY (R R) & SONS CO	14.1	14.4	-8.3	8.1	20.4	25.3	22.5	2.4	15.8	18.6	7.4	3.6	10.2	11.9
ENNIS INC	31.2	25.2	16.9	12.5	17.1	17.6	14.7	16.0	15.8	17.3	12.0	14.2	13.6	17.2
ETHAN ALLEN INTERIORS INC	15.2	12.5	13.6	20.1	24.8	24.5	24.4	18.6	16.9	14.4	16.0	17.8	20.1	18.4
EW SCRIPPS -CL A	12.6	11.7	14.7	15.8	12.4	13.2	13.4	10.5	13.1	16.2	15.5	11.4	14.5	13.5
EXPEDITORS INTL WASH INC	14.0	15.9	18.9	24.8	24.4	23.7	25.8	25.0	24.0	20.9	21.5	25.4	23.7	22.2
FAMILY DOLLAR STORES	17.9	14.9	14.2	15.8	19.2	22.1	23.1	21.6	20.5	20.1	19.5	15.7	14.8	18.4
FARMER BROS CO	5.3	9.5	10.4	7.0	12.8	10.3	12.5	11.1	8.5	6.4	4.0	-2.0	1.8	7.5
FASTENAL CO	31.8	33.8	29.5	28.0	27.6	26.2	25.2	17.9	16.2	15.6	20.8	22.7	23.3	24.5
FLEXSTEEL INDUSTRIES INC	9.3	7.2	6.1	8.1	9.9	13.0	14.3	5.4	6.6	9.1	10.4	5.9	4.4	8.4
FLUOR CORP	17.0	17.5	17.3	8.6	14.4	6.7	7.8	1.6	19.6	17.1	15.4	15.3	15.7	13.4
FORTUNE BRANDS INC	16.5	12.8	13.2	2.7	7.2	-26.2	-5.7	18.3	23.9	23.1	26.8	18.4	19.8	11.6
FRANKLIN ELECTRIC CO INC	32.3	21.3	23.9	26.5	26.9	28.5	20.9	22.7	23.3	19.9	17.8	18.3	18.6	23.1
FREDS INC	7.5	2.4	4.9	7.9	6.6	7.6	9.7	10.4	12.0	12.5	9.2	8.0	7.5	8.2
FRISCH'S RESTAURANTS INC	3.7	3.6	1.8	7.9	8.4	11.2	13.9	13.5	14.9	14.1	17.1	9.4	8.9	9.9
G&K SERVICES INC -CL A	15.5	16.7	17.5	18.7	17.5	17.1	14.9	11.8	11.9	9.4	8.8	8.9	8.2	13.6
GANNETT CO	25.0	24.1	37.2	22.2	26.8	22.3	35.3	15.3	18.3	15.8	15.9	15.8	14.6	22.2
GENERAL DYNAMICS CORP	19.1	22.3	16.5	17.4	17.6	32.7	25.8	22.6	18.9	18.1	18.7	19.1	20.7	20.7
GENERAL ELECTRIC CO	18.1	23.5	24.0	25.0	25.4	26.3	27.4	26.8	25.5	21.8	17.7	15.2	18.8	22.7
GENUINE PARTS CO	19.4	19.5	19.5	19.1	18.2	17.9	17.4	12.9	16.4	15.9	16.3	16.7	18.1	17.5
GORMAN-RUPP CO	15.7	14.7	14.2	14.1	14.5	14.9	14.3	14.0	8.1	8.6	7.8	8.8	14.9	12.7
GRAINGER (W W) INC	13.0	16.9	15.8	16.8	18.5	13.1	12.8	11.1	14.4	12.9	14.7	15.9	17.2	14.8
HARTE HANKS INC	24.9	24.9	19.4	82.2	12.0	12.6	14.5	14.4	16.7	16.1	17.3	20.2	21.2	22.8
HAVERTY FURNITURE	10.0	9.0	8.4	8.6	10.6	16.8	16.0	11.9	11.4	10.2	8.6	5.5	5.6	10.2
HEICO CORP	5.6	9.4	27.6	13.9	16.5	15.8	17.0	8.8	7.7	5.7	8.8	8.8	10.8	12.0
HNI CORP	29.1	20.0	29.1	27.4	25.2	18.1	19.8	12.8	14.7	14.5	16.5	21.8	22.6	20.9
HORMEL FOODS CORP	19.2	17.3	10.5	13.8	17.2	19.8	19.9	19.5	17.9	15.7	17.5	17.0	16.9	17.1
HUBBELL INC -CL B	18.3	19.1	20.1	16.6	20.3	17.2	17.0	6.4	14.7	14.6	17.4	17.0	15.7	16.5
ILLINOIS TOOL WORKS	19.8	22.4	22.5	22.6	21.9	20.6	18.8	14.1	14.7	14.1	17.3	19.7	20.7	19.2
INTERPOOL INC	16.6	14.3	11.4	12.1	14.1	7.5	13.3	11.7	1.3	11.4	2.0	14.6	21.2	11.7
INTL SPEEDWAY CORP -CL A	23.6	23.9	20.5	18.8	13.9	8.9	5.4	8.8	12.8	15.6	19.4	16.6	10.6	15.3
JOHNSON CONTROLS INC	13.9	14.9	16.1	17.7	18.4	19.6	19.4	17.2	18.6	17.7	17.4	16.1	15.4	17.1
KAMAN CORP	-10.6	10.5	12.1	31.6	10.7	8.0	11.4	3.5	-10.7	6.5	-4.0	4.7	11.2	6.5
KELLY SERVICES INC -CL A	14.9	15.3	14.7	15.0	15.4	15.2	14.5	2.7	3.0	0.8	3.4	5.9	8.9	10.0
KENNAMETAL INC	3.8	19.1	16.8	16.0	11.9	5.3	6.8	6.8	5.1	2.5	9.1	12.8	22.6	10.7
KIMBERLY-CLARK CORP	21.2	1.1	34.5	20.5	27.3	36.6	33.2	28.2	29.8	27.3	26.9	25.9	25.7	26.0
LANCASTER COLONY CORP	27.9	27.4	25.3	25.7	24.7	23.1	23.9	20.6	19.1	21.5	14.1	15.9	15.3	21.9
LANCE INC	11.2	-3.2	12.9	16.2	14.8	13.5	12.4	13.5	11.1	10.1	13.0	9.2	8.7	11.0
LAWSON PRODUCTS	15.1	16.6	15.9	15.9	13.8	16.3	18.2	5.5	7.7	9.6	12.1	14.6	7.3	13.0
LA-Z-BOY INC	11.8	11.8	12.9	13.4	16.5	16.3	10.1	8.8	14.5	0.4	6.7	-0.6	0.8	9.5
LEE ENTERPRISES INC	21.9	21.1	14.3	19.9	19.5	20.2	22.3	58.3	11.5	10.1	10.3	8.5	7.4	18.9
LEGGETT & PLATT INC	20.2	19.8	18.3	19.7	19.0	18.8	15.4	10.3	12.1	10.1	12.9	11.0	13.1	15.4

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Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
LENNAR CORP	13.6	12.3	13.5	14.9	25.0	21.6	21.7	28.9	28.0	27.4	25.8	29.1	10.8	21.0
LIMITED BRANDS INC	17.2	32.3	16.9	11.0	96.0	21.0	19.2	20.5	13.2	14.2	18.6	27.7	24.9	25.6
LINCOLN ELECTRIC HLDGS INC	28.4	23.5	20.6	20.6	20.2	15.7	17.4	17.7	14.4	12.0	15.3	19.9	23.3	19.1
LINDSAY CORP	18.2	17.1	22.7	24.5	26.4	14.7	16.5	10.0	12.4	13.2	8.6	4.4	10.2	15.3
LIZ CLAIBORNE INC	8.4	12.9	15.5	19.0	17.8	20.4	21.3	20.3	19.7	19.5	18.5	16.6	12.3	17.1
LOCKHEED MARTIN CORP	26.4	11.8	22.8	-10.5	17.7	11.8	-6.3	-14.9	8.1	16.7	18.4	24.5	34.3	12.4
LONGS DRUG STORES CORP	9.5	8.8	10.9	10.1	10.4	10.3	6.5	6.7	4.4	4.2	5.1	9.9	9.4	8.2
LOWE'S COMPANIES INC	19.5	14.7	15.1	14.8	16.8	17.2	15.9	16.8	19.6	20.2	19.9	21.4	20.7	17.9
LSI INDUSTRIES INC	19.2	23.1	16.1	14.5	17.2	18.9	15.6	8.1	10.6	5.9	6.8	11.0	9.5	13.6
MARCUS CORP	11.8	18.2	11.7	9.8	7.5	7.1	6.6	6.5	5.7	6.4	22.4	7.1	10.7	10.1
MASCO CORP	9.4	-23.4	16.9	18.8	19.2	19.4	18.0	5.3	14.5	15.0	16.4	18.3	10.5	12.2
MATTEL INC	26.4	30.0	27.7	17.1	17.8	-4.6	-25.6	19.8	26.0	25.6	24.9	18.6	26.2	17.7
MATTHEWS INTL CORP -CL A	21.2	19.5	21.4	19.0	21.6	22.9	23.1	23.4	23.5	20.5	19.8	18.5	18.3	21.0
MCCORMICK & COMPANY INC	12.8	19.3	10.3	23.3	26.6	26.8	37.1	35.7	34.1	31.6	26.1	25.4	23.3	25.6
MDC HOLDINGS INC	10.5	8.7	9.9	10.9	19.5	26.0	28.3	27.4	23.0	23.4	32.1	30.0	10.4	20.0
MEDIA GENERAL -CL A	41.9	15.0	17.3	12.3	15.8	97.6	4.3	1.6	4.8	6.2	7.0	7.9	8.5	18.5
MEREDITH CORP	10.0	16.0	21.5	32.4	23.6	25.3	19.2	17.2	19.1	18.1	20.3	20.7	21.5	20.4
MET-PRO CORP	12.5	14.6	16.2	16.9	15.9	15.7	17.0	12.7	11.1	10.9	7.8	11.2	10.3	13.3
MINE SAFETY APPLIANCES CO	5.9	7.4	9.4	9.2	7.6	6.8	10.0	13.4	13.1	22.1	20.9	21.7	15.7	12.6
MOLSON COORS BREWING CO	8.9	6.3	6.2	11.3	9.0	11.4	12.4	13.1	16.7	15.5	13.7	4.0	6.5	10.4
MOVADO GROUP INC	16.9	9.8	11.2	12.7	13.4	8.7	13.5	10.3	9.8	8.9	8.9	8.3	14.3	11.3
NATIONAL PRESTO INDS INC	9.0	7.7	6.0	6.8	7.8	8.2	6.1	2.6	3.7	6.4	6.2	7.3	10.2	6.8
NEW YORK TIMES CO -CL A	13.6	8.6	5.2	15.6	17.6	20.8	29.1	36.6	24.8	22.7	21.0	18.2	-46.5	14.4
NEWELL RUBBERMAID INC	18.6	18.3	18.4	18.1	21.8	4.1	16.4	10.8	13.9	-2.3	-6.1	14.8	21.8	13.0
NIKE INC -CL B	21.6	25.2	28.5	12.5	13.7	17.9	17.8	18.2	18.9	21.6	23.2	23.3	22.4	20.4
NORDSON CORP	22.8	23.7	22.3	21.5	9.6	21.8	23.3	9.6	8.3	12.4	18.0	21.3	23.8	18.3
NORFOLK SOUTHERN CORP	14.4	15.0	15.7	13.8	12.9	4.0	2.9	6.3	7.3	6.2	12.3	14.8	15.7	10.9
NORTHROP GRUMMAN CORP	2.7	18.3	13.0	17.1	7.1	15.8	16.9	7.2	4.3	5.7	6.7	8.4	9.2	10.2
OIL DRI CORP AMERICA	14.1	10.6	4.3	8.8	6.3	9.8	3.0	1.3	-1.6	4.5	7.1	9.0	7.2	6.5
PENTAIR INC	13.2	17.0	14.3	15.9	16.6	12.5	5.7	3.2	12.3	11.9	12.6	12.3	11.4	12.2
PEPSIAMERICAS INC	19.3	22.6	22.0	0.7	14.3	-1.2	6.2	1.3	9.0	10.5	11.4	12.2	10.0	10.6
PULTE HOMES INC	26.1	7.9	22.6	6.4	11.8	17.7	16.1	17.1	18.0	20.1	24.8	28.5	11.0	17.5
RAVEN INDUSTRIES INC	14.1	13.1	14.5	13.6	10.0	11.6	12.5	17.7	20.3	22.2	27.0	32.2	27.9	18.2
RAYTHEON CO	14.5	19.3	17.1	7.0	8.1	4.2	1.3	-6.8	-1.3	4.0	3.8	8.2	11.8	7.0
ROBBINS & MYERS INC	11.6	18.6	25.2	26.7	22.7	7.8	11.2	10.8	6.3	5.2	3.3	-0.1	-6.1	11.0
ROLLINS INC	28.0	19.3	11.3	0.9	5.8	9.4	12.7	20.6	30.8	31.2	38.0	30.6	29.8	20.6
RUBY TUESDAY INC	26.6	-1.3	11.9	13.3	16.8	16.2	23.0	18.8	23.6	23.6	18.9	18.5	19.0	17.6
RUDDICK CORP	11.2	12.9	12.9	13.1	11.8	11.9	11.1	-0.2	11.5	12.6	12.4	11.8	11.3	11.1
RYDER SYSTEM INC	14.5	13.1	-2.7	16.2	14.8	36.9	7.2	1.5	9.6	11.1	15.1	15.1	15.3	12.9
SCHAWK INC -CL A	23.6	7.3	-41.9	21.0	38.7	17.9	15.1	10.4	16.0	17.3	19.1	16.8	11.3	13.3
SHERWIN-WILLIAMS CO	17.9	17.7	17.5	17.4	16.5	17.8	1.0	17.8	22.0	23.7	25.3	27.4	30.9	19.5

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Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
SKYLINE CORP	8.8	10.8	11.6	11.1	13.6	7.8	5.8	6.3	3.1	3.1	2.8	7.4	1.4	7.2
SMITH (A O) CORP	19.7	17.9	16.4	37.3	11.1	10.2	6.8	3.2	10.7	9.6	6.1	7.7	11.8	13.0
SMUCKER (JM) CO	14.7	11.0	10.9	12.2	12.1	8.3	11.3	11.7	13.7	9.5	8.9	8.4	8.9	10.9
SOUTHWEST AIRLINES	15.6	13.7	13.5	17.4	19.7	18.1	19.9	13.7	5.7	9.3	5.9	9.0	7.6	13.0
SPARTAN MOTORS INC	18.4	5.6	3.8	-24.1	7.5	-3.2	-15.2	18.1	25.1	10.3	9.1	11.8	19.1	6.7
STANDEX INTERNATIONAL CORP	22.6	30.5	23.0	19.5	14.0	20.3	16.9	14.8	11.6	8.3	6.5	13.9	12.3	16.5
STANLEY WORKS	17.6	8.0	12.8	-6.0	21.6	21.4	26.4	20.2	20.4	11.7	35.3	20.2	19.3	17.6
SUPERIOR INDUSTRIES INTL	29.9	24.7	19.5	20.6	17.5	21.3	21.2	13.1	16.0	13.1	7.5	-1.2	-1.6	15.5
SUPERIOR UNIFORM GROUP INC	14.5	5.4	12.1	12.0	10.0	11.2	9.0	7.9	6.5	6.9	6.3	1.5	2.9	8.2
TELEFLEX INC	14.2	14.7	15.0	16.1	16.5	16.7	16.9	15.3	14.8	11.1	0.9	12.3	12.0	13.6
TENNANT CO	17.5	18.7	17.3	18.4	19.1	14.9	19.3	3.0	5.4	8.9	7.9	12.5	14.1	13.6
TOOTSIE ROLL INDUSTRIES INC	16.8	15.7	16.1	18.3	18.1	17.2	17.0	13.6	12.8	12.2	11.6	13.0	10.6	14.9
TORO CO	14.2	20.7	18.2	16.1	1.6	12.9	15.2	15.3	17.0	20.3	24.7	29.0	33.0	18.3
TREDEGAR CORP	22.7	14.1	23.5	24.1	23.6	15.4	25.6	2.0	-0.5	-5.8	6.3	3.4	7.6	12.5
TWIN DISC INC	6.9	8.1	8.8	10.4	12.0	-1.4	5.2	9.0	3.5	-4.4	10.4	11.0	18.5	7.5
TYSON FOODS INC -CL A	-0.2	15.9	5.8	11.7	1.4	11.2	7.0	3.2	10.9	8.9	9.8	8.3	-4.2	6.9
UNIFIRST CORP	13.4	13.0	13.7	14.1	14.3	9.6	7.5	8.3	9.0	9.1	9.6	11.1	9.1	10.9
UNION PACIFIC CORP	10.9	16.5	12.4	5.3	-8.1	10.5	10.1	10.6	13.3	11.4	4.8	7.8	11.1	9.0
UNITED INDUSTRIAL CORP	6.0	1.0	7.3	15.4	12.3	5.7	6.9	4.6	-46.5	-13.2	73.9	143.5	106.2	24.9
UNITED PARCEL SERVICE INC	22.0	21.3	20.7	15.2	26.3	9.0	26.4	24.3	28.7	21.2	21.3	23.3	26.0	22.0
UNITED TECHNOLOGIES CORP	15.3	18.6	21.0	24.8	28.9	26.1	24.0	23.8	26.4	23.3	21.7	20.4	21.8	22.8
UNIVERSAL CORP/VA	9.7	6.7	17.7	22.7	27.8	23.4	22.0	21.5	18.7	14.8	12.1	1.0	3.7	15.5
VF CORP	16.5	8.8	15.8	18.0	19.4	17.0	12.1	6.1	19.3	21.9	21.2	19.4	17.5	16.4
WALGREEN CO	19.1	19.1	19.4	19.7	20.6	19.7	20.1	18.8	17.8	17.5	17.6	18.3	18.4	18.9
WAL-MART STORES INC	22.8	19.9	19.2	19.8	22.4	23.8	22.0	20.1	21.6	21.8	22.1	21.9	19.7	21.3
WASHINGTON POST -CL B	15.3	16.5	17.6	22.4	30.0	15.2	9.5	14.4	12.2	12.3	14.8	12.4	11.3	15.7
WASTE MANAGEMENT INC	17.2	11.8	4.2	14.4	-21.9	-9.0	-2.1	9.9	15.4	13.2	16.1	19.6	18.6	8.3
WATTS WATER TECHNOLOGIES INC	11.8	11.9	-13.9	15.8	15.1	9.4	7.7	11.0	12.0	9.1	10.1	10.8	11.0	9.4
WEIS MARKETS INC	10.2	10.2	9.8	9.4	9.6	8.8	7.9	6.8	11.0	9.7	10.0	10.8	9.1	9.5
WERNER ENTERPRISES INC	13.9	12.4	12.3	13.0	13.7	12.8	9.3	8.5	10.0	10.9	11.8	12.0	11.4	11.7
WEYCO GROUP INC	10.1	11.0	13.1	14.4	14.9	16.6	15.3	13.1	16.7	18.7	18.6	15.1	15.4	14.8
WILEY (JOHN) & SONS -CL A	20.2	22.8	16.5	25.3	24.6	31.3	30.0	23.1	28.1	23.4	20.7	27.6	21.4	24.2
WOLVERINE WORLD WIDE	13.5	14.3	14.8	15.9	14.3	10.2	3.2	12.7	12.9	12.9	14.8	16.2	17.3	13.3
WOODWARD GOVERNOR CO	-1.6	6.1	10.9	8.7	10.0	13.3	18.2	17.9	13.4	3.5	8.4	13.7	15.3	10.6
Mean	**15.7**	**14.6**	**14.5**	**15.3**	**15.6**	**15.5**	**14.3**	**12.8**	**13.9**	**13.4**	**14.3**	**15.6**	**14.9**	**14.6**
Median	**15.1**	**14.9**	**15.4**	**15.4**	**15.9**	**15.5**	**15.0**	**12.7**	**13.9**	**12.5**	**13.3**	**14.9**	**14.6**	**13.6**
Average of Annual Medians														**14.5**

Source: Standard & Poor's Research Insight

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES

Company	Stock Price (Average Monthly High/Low 7/2002-6/2007) (1)	Book Value Per Share Average 2002-2006 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Permanent Capital Common Equity Ratio 2002-2006 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
CANADIAN UTILITIES -CL A	33.57	16.52	2.03	37.7%	55.1%	44.9%
EMERA INC	18.53	12.37	1.50	46.1%	56.1%	43.9%
ENBRIDGE INC	29.94	11.04	2.71	34.1%	58.3%	41.7%
FORTIS INC	18.77	10.34	1.82	33.5%	47.7%	52.3%
PNG	18.08	20.62	0.88	46.4%	43.1%	56.9%
TERASEN INC [1/]	24.47	13.62	1.80	39.9%	54.4%	45.6%
TRANSCANADA CORP	30.10	14.01	2.15	38.1%	57.0%	43.0%
Mean				**39.4%**	**53.1%**	**46.9%**

1/ Terasen price is through November 2005 due to Kinder Morgan acquisition; book value per share is through 2005.

Sources: Standard & Poor's Research Insight

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES

Company	Stock Price (Average Daily Closing 7/16-8/15/2007) (1)	Book Value Per Share (Avg. 2005 and 2006) (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Permanent Capital Common Equity Ratio 2006 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
AGL Resources	38.77	19.99	1.94	49.8%	65.8%	34.2%
Consolidated Edison	45.41	30.38	1.49	48.4%	58.4%	41.6%
FPL	59.01	23.01	2.56	50.9%	72.6%	27.4%
Integrys Energy	50.78	33.95	1.50	53.4%	63.2%	36.8%
New Jersey Resources	48.91	19.20	2.55	65.2%	82.7%	17.3%
Nicor Inc.	41.20	18.90	2.18	63.7%	79.2%	20.8%
Northwest Nat. Gas	44.12	21.63	2.04	53.7%	70.3%	29.7%
NSTAR	32.21	14.59	2.21	39.7%	59.2%	40.8%
Piedmont Natural Gas	24.64	11.61	2.12	51.7%	69.4%	30.6%
Scana	38.11	23.80	1.60	47.2%	58.9%	41.1%
Southern Co.	34.87	14.82	2.35	46.2%	66.9%	33.1%
Vectren	26.45	15.24	1.74	49.3%	62.8%	37.2%
WGL Holdings Inc.	31.65	18.61	1.70	60.4%	72.2%	27.8%
Mean				**52.3%**	**67.8%**	**32.2%**

Sources: Schedule 14 for stock prices and Standard & Poor's Research Insight

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: CANADIAN UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

THEORY 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity rises as leverage (debt ratio) rises, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Wherevered (lower debt ratio)

ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.0%[1]
Equity Cost	=	Cost of Equity[2]
	=	9.75%
Tax Rate	=	34.0%[3]

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (average market value common equity ratio of 53%)

   $WACC_{AT}$ = (6.0%)(1-.34)(47%) + (9.75%)(53%)

   = 7.03%

2. Estimate Cost of Equity for sample at 39% book value common equity ratio with $WACC_{AT}$ unchanged at 7.03%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

   7.03% = (6.0%)(1-.34)(61%)+(X)(39%)

   Cost of Equity at 39% Equity Ratio = 11.80%

3. Difference between Equity Return at 39% and 53% common equity ratios:

   11.8% - 9.75% = 2.05% (205 basis points)

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on the mid-point of Equity Risk Premium and DCF tests.
[3] Combined Federal/Ontario tax rate.

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times \frac{(1\text{-}tD_{ML})}{(1\text{-}tD_{LL})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.00%
Equity Cost	=	Cost of Equity
	=	9.75%
Tax Rate	=	34.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (average market value common equity ratio of 53%)

$WACC_{AT}$ = (6.0%)(1-.34)(47%) + (9.75%)(53%)
= 7.03%

2. Estimate $WACC_{AT}$ for more levered firm (book value common equity ratio of 39%)

$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1\text{-}t \times \text{Debt Ratio}_{ML})/(1\text{-}t \times \text{Debt Ratio}_{LL})$

$$WACC_{AT(ML)} = 7.03\% \times \frac{(1\text{-}.34 \times 61\%)}{(1\text{-}.34 \times 47\%)}$$

$WACC_{AT(ML)} = 6.63\%$

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})
6.63% = (6.0%)(1-.34)(61%) + (X)(39%)

Cost of Equity at 39% equity ratio = 10.80%

4. Difference between Equity Return at 39% and 53% common equity ratios:

10.8% - 9.75% = 1.05% (105 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
105 - 205 BASIS POINTS

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: BENCHMARK LOW RISK U.S. GAS & ELECTRIC UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

THEORY 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity rises as leverage (debt ratio) rises, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)

ML = more levered (higher debt ratio)

9.5

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.0%[1]
Equity Cost	=	Cost of Equity[2]
	=	9.75%
Tax Rate	=	34.0%[3]

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (average market value common equity ratio of 68%)

   $WACC_{AT}$ = (6.0%)(1-.34)(32%) + (9.75%)(68%)

   = 7.90%

2. Estimate Cost of Equity for sample at 52% book value common equity ratio with $WACC_{AT}$ unchanged at 7.90%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

   7.90% = (6.0%)(1-.34)(48%)+(X)(52%)

   Cost of Equity at 52% Equity Ratio = 11.50%

3. Difference between Equity Return at 52% and 68% common equity ratios:

   11.5% - 9.75% = 1.75% (175 basis points)

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on the mid-point of Equity Risk Premium and DCF tests.
[3] Combined Federal/Ontario tax rate.

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times \frac{(1\text{-}tD_{ML})}{(1\text{-}tD_{LL})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.00%
Equity Cost	=	Cost of Equity
	=	9.75%
Tax Rate	=	34.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (average market value common equity ratio of 68%)

$WACC_{AT}$ = (6.0%)(1-.34)(32%) + (9.75%)(68%)
= 7.90%

2. Estimate $WACC_{AT}$ for more levered firm (book value common equity ratio of 52%)

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 7.90\% \times \frac{(1\text{-}.34 \times 48\%)}{(1\text{-}.34 \times 32\%)}$$

$WACC_{AT(ML)}$ = 7.42%

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 $Ratio_{ML}$)
7.42% = (6.0%)(1-.34)(48%) + (X)(52%)

Cost of Equity at 52% equity ratio = 10.6%

4. Difference between Equity Return at 52% and 68% common equity ratios:

10.6% - 9.75% = .85% (85 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
85 -175 BASIS POINTS

CAPITAL STRUCTURE RATIOS OF CANADIAN UTILITIES (2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd. [4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	EBITDA Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities				
AltaLink L.P.	1.8	3.4	11.4	3.1
CU Inc.	2.7	4.1	18.7	3.6
Enersource	2.1	na	16.7	3.8
ENMAX Corp.	6.4	8.5	46.3	8.1
EPCOR Utilities Inc.	3.0	4.2	23.4	4.2
FortisAlberta Inc.[2/]	2.3	4.5	17.5	3.0
FortisBC Inc.[2/]	2.2	3.1	10.9	2.8
Hamilton Utilities	3.4	5.6	32.0	4.7
Hydro One Inc.	3.2	4.6	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	5.0	26.1	5.7
Maritime Electric	2.5	3.3	12.9	2.6
Newfoundland Power [2/]	2.4	3.3	14.0	2.9
Nova Scotia Power	2.4	3.5	14.2	3.3
Toronto Hydro	2.7	4.0	17.5	3.4
Gas Distributors				
Enbridge Gas Distribution	2.1	2.8	12.5	3.0
Gaz Metropolitain	2.5	3.9	24.0	4.6
Pacific Northern Gas [4/]	2.5	3.7	26.4	3.2
Terasen Gas	2.0	2.7	9.7	2.4
Union Gas [3/]	2.1	3.1	12.8	2.8
Pipelines				
Enbridge Pipelines [3/]	3.3	2.8	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	3.7	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	3.4	15.7	2.8
Westcoast Energy Inc.	2.1	3.1	16.4	3.1
Medians				
Electric T&D	**2.7**	**4.5**	**17.5**	**3.8**
Electric Integrated	**2.5**	**3.5**	**14.2**	**3.3**
All Electric	**2.6**	**4.1**	**17.5**	**3.5**
Gas Distributors	**2.1**	**3.1**	**12.8**	**3.0**
All Companies	**2.5**	**3.6**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] EBIT and EBITDA from DBRS, FFO data from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT AND COMMON STOCK QUALITY RATINGS OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
ENMAX	Unsecured Debentures (DBRS) Issuer (S&P)	A		A-	
Enersource	Issuer	A			
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [2/]	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured Senior Unsecured	A A	A2 A3	AA- A	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
TransCanada PipeLines	Senior Secured Senior Unsecured	A A	 A2	A A-	Very conservative
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Veridian Corp.	Issuer	A			
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Mean		**A**	**A3**	**A-**	**Very conservative**
Median		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P			S&P Credit Stats					
					Average 2003-2005				
Name	Debt Rating	Business Profile	2005 Debt Ratio 1/	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	Average ROE 2003-2005
Madison Gas & Electric Co.	AA-	4	50.0	55.5	54.9	4.5	20.7	5.3	11.1
Alabama Power Co.	A	4	52.6	56.8	56.6	3.6	23.4	5.1	13.7
Boston Edison Co.	A+	1	55.7	56.8	64.7	4.2	22.7	4.9	15.2
Central Hudson Gas & Electric Corp.	A	3	54.0	68.0	70.1	4.4	15.9	3.6	13.3
Consolidated Edison Co. of New York Inc.	A	2	49.8	59.6	57.2	2.8	19.2	4.0	10.5
Consolidated Edison Inc.	A	2	52.2	62.1	59.2	2.5	17.2	3.8	8.8
Florida Power & Light Co.	A	4	40.4	40.4	39.0	6.7	32.3	7.6	12.3
FPL Group Inc.	A	5	55.5	51.7	51.9	2.7	19.4	4.4	12.2
Georgia Power Co.	A	4	51.6	53.5	54.2	4.8	25.5	6.1	14.1
Gulf Power Co.	A	4	53.1	52.5	54.1	3.8	21.6	4.9	12.3
KeySpan Corp.	A	4	50.7	61.0	64.1	3.2	16.0	3.8	11.4
MidAmerican Energy Co.	A-	5	47.9	49.1	49.9	4.8	31.7	6.5	14.1
MidAmerican Energy Holdings Co.	A-	4	77.4	77.8	80.0	2.4	10.6	3.2	13.3
Mississippi Power Co.	A	4	44.7	50.6	50.3	5.7	35.4	9.2	13.9
Orange and Rockland Utilities Inc.	A	2	56.9	77.8	71.7	3.7	17.5	4.1	12.6
PacifiCorp	A-	5	50.7	59.0	61.9	2.5	15.9	3.6	8.3
PPL Electric Utilities Corp.	A-	3	64.1	53.9	53.8	1.8	33.8	5.1	4.0
Public Service Co. of North Carolina Inc.	A-	2	41.3	41.4	40.5	3.0	18.0	3.7	5.3
San Diego Gas & Electric Co.	A	5	55.9	61.5	57.3	5.0	30.7	6.5	20.9
Savannah Electric & Power Co.	A	4	51.3	54.9	56.7	3.7	21.8	4.8	na
SCANA Corp.	A-	4	56.1	57.9	59.7	2.5	21.4	4.6	12.0
South Carolina Electric & Gas Co.	A-	4	48.6	48.4	49.9	2.8	24.6	4.8	10.8
Southern Co.	A	4	57.1	56.7	56.6	4.3	23.5	5.5	15.5
Vectren Corp.	A-	4	57.6	59.7	59.7	2.9	16.7	4.0	11.2
Wisconsin Electric Power Co.	A-	4	50.7	48.8	48.0	5.2	31.2	7.6	12.1
Wisconsin Power & Light Co.	A-	4	35.5	49.8	42.6	4.3	36.8	6.4	11.0
Wisconsin Public Service Corp.	A+	4	36.1	36.1	40.6	4.7	28.4	4.9	10.4
WPS Resources Corp.	A	5	45.6	55.9	56.8	3.6	16.6	4.4	12.3
Mean	**A**	**4**	**51.6**	**55.6**	**55.8**	**3.8**	**23.3**	**5.1**	**12.0**
Median	**A**	**4**	**51.6**	**55.9**	**56.6**	**3.7**	**21.8**	**4.8**	**12.2**

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

Name	S&P			S&P Credit Stats	Average 2003-2005				Average ROE 2003-2005
	Debt Rating	Business Profile	2005 Debt Ratio [1/]	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	
AEP Texas Central Co.	BBB	3	67.0	57.8	54.5	2.4	12.5	2.2	15.7
AEP Texas North Co.	BBB	3	46.7	47.6	53.0	4.1	28.6	4.9	19.0
ALLETE Inc.	BBB+	6	39.3	55.4	48.9	1.9	21.0	4.7	10.1
Alliant Energy Corp.	BBB+	5	46.9	55.2	54.8	2.3	21.5	3.9	4.9
Ameren Corp.	BBB	7	46.3	52.1	54.3	3.8	19.5	4.8	11.0
AmerenEnergy Generating Co.	BBB	9	66.3	67.4	73.2	2.7	20.2	3.4	24.3
American Electric Power Co. Inc.	BBB	5	57.7	66.4	68.5	2.4	15.7	3.3	8.6
Appalachian Power Co.	BBB	5	56.4	57.5	58.9	2.8	15.2	3.6	11.7
Arizona Public Service Co.	BBB-	6	46.2	52.4	59.6	2.8	17.2	4.4	7.9
Atlantic City Electric Co.	BBB	3	66.2	51.5	52.7	2.3	19.2	2.6	9.9
Baltimore Gas & Electric Co.	BBB+	5	45.1	46.6	52.2	3.2	22.8	4.2	10.4
CenterPoint Energy Houston Electric LLC	BBB	2	71.1	70.9	54.4	2.5	33.0	3.5	13.6
CenterPoint Energy Inc.	BBB	3	87.3	89.7	90.7	1.5	16.7	2.7	16.3
CenterPoint Energy Resources Corp.	BBB	4	41.5	59.5	63.2	1.5	11.4	2.6	6.5
Central Illinois Light Co.	BBB-	8	35.0	36.0	44.2	3.8	28.6	7.5	6.5
Central Illinois Public Service Co.	BBB-	8	43.5	43.6	49.6	2.6	16.8	3.8	na
CILCORP Inc.	BBB-	8	56.7	57.0	61.6	1.2	10.1	2.6	2.2
Cincinnati Gas & Electric Co.	BBB	6	47.7	67.3	64.4	3.0	15.6	4.1	15.0
Cinergy Corp.	BBB	6	55.2	61.7	63.0	2.6	14.5	3.6	na
Cleco Corp.	BBB	6	47.9	52.0	61.0	3.9	27.3	5.3	11.3
Cleco Power LLC	BBB	6	50.7	52.6	51.1	3.6	31.4	6.1	12.2
Cleveland Electric Illuminating Co.	BBB	6	54.9	56.3	57.3	3.1	13.4	3.3	12.5
Columbus Southern Power Co.	BBB	4	55.5	58.2	55.9	4.3	25.0	5.3	16.5
Commonwealth Edison Co.	BBB-	8	42.7	37.9	38.9	4.4	24.5	4.1	3.9
Connecticut Light & Power Co.	BBB	3	64.6	60.4	61.4	2.4	21.8	5.6	9.8
Constellation Energy Group Inc.	BBB+	7	48.8	56.6	57.8	3.2	21.6	4.0	12.4
Delmarva Power & Light Co.	BBB	3	51.9	62.1	68.2	2.8	13.2	2.8	10.7
Detroit Edison Co.	BBB	6	62.3	67.2	68.4	2.4	14.9	3.6	8.1
Dominion Resources Inc.	BBB	7	63.6	61.6	61.0	2.5	17.0	3.6	8.0
DTE Energy Co.	BBB	6	60.2	64.4	64.3	1.6	11.8	3.2	9.5
Duke Energy Corp.	BBB	6	49.4	50.6	54.3	2.5	19.4	3.9	4.2
Duquesne Light Co.	BBB	4	45.0	51.6	59.1	3.2	16.2	3.7	11.8
Edison International	BBB-	6	57.3	60.5	63.2	3.1	21.2	4.3	17.0
El Paso Electric Co.	BBB	6	53.2	57.7	57.2	1.9	23.1	4.1	5.8
Empire District Electric Co.	BBB-	6	52.9	57.1	57.9	2.3	16.8	3.6	6.7
Energy East Corp.	BBB+	3	58.7	63.0	64.7	2.2	14.4	3.1	8.8
Entergy Arkansas Inc.	BBB	5	47.5	54.6	56.1	3.7	29.5	6.2	10.6
Entergy Corp.	BBB	6	53.1	59.3	55.6	3.4	21.0	4.5	10.5
Entergy Gulf States Inc.	BBB	6	51.7	51.8	55.0	2.6	15.4	3.4	8.1
Entergy Louisiana LLC	BBB	5	50.6	54.7	52.8	4.1	31.1	6.1	13.0
Entergy Mississippi Inc.	BBB	6	52.7	56.8	58.0	3.1	29.7	6.0	12.2
Exelon Corp.	BBB+	7	60.3	66.8	64.3	3.5	30.4	3.8	13.6
FirstEnergy Corp.	BBB	6	53.8	61.4	63.8	2.6	17.3	3.9	8.2
Great Plains Energy Inc.	BBB	7	48.3	56.9	61.9	3.4	24.1	4.9	15.3
Green Mountain Power Corp.	BBB	5	45.2	74.1	76.4	1.8	7.9	2.2	10.6
Hawaiian Electric Co. Inc.	BBB+	5	45.7	54.1	52.9	3.2	25.4	5.8	10.2
IDACORP Inc.	BBB+	5	51.8	58.2	57.0	1.8	14.5	3.7	6.5
Idaho Power Co.	BBB+	5	51.2	51.8	51.7	2.4	16.7	3.8	7.4
Illinois Power Co.	BBB-	8	44.6	43.1	51.4	2.6	15.9	3.1	8.7
Indiana Michigan Power Co.	BBB	6	56.3	68.4	69.7	2.3	15.7	3.7	11.1
Interstate Power & Light Co.	BBB+	5	46.5	51.3	50.3	3.6	24.7	5.1	10.8
Jersey Central Power & Light Co.	BBB	4	29.7	26.5	30.6	3.3	24.0	4.8	3.8
Kansas City Power & Light Co.	BBB	6	46.9	49.4	56.2	3.5	25.8	5.0	14.0
Kentucky Power Co.	BBB	5	58.8	60.9	62.8	2.1	14.9	3.5	8.4
Kentucky Utilities Co.	BBB+	5	44.4	51.7	51.1	6.2	23.4	7.5	11.8
Louisville Gas & Electric Co.	BBB+	5	46.7	52.5	53.1	5.3	21.5	6.8	10.9
Metropolitan Edison Co.	BBB	4	38.7	39.8	38.8	2.7	13.0	3.5	4.5
NiSource Inc.	BBB	4	56.9	62.0	62.9	2.4	13.2	3.1	6.0
Northeast Utilities	BBB	5	63.5	61.8	61.3	0.9	19.4	4.3	-0.1
Northern Indiana Public Service Co.	BBB	5	41.1	47.6	52.5	6.0	32.4	8.7	16.0
Northern States Power Co.	BBB	5	51.2	55.6	55.5	2.7	22.2	4.1	11.3
Northern States Power Wisconsin	BBB+	4	46.5	46.9	45.9	4.0	24.9	4.7	10.8
OGE Energy Corp.	BBB+	6	50.1	58.4	62.2	3.4	22.5	4.7	13.5
Ohio Edison Co.	BBB	6	36.8	47.5	49.1	5.5	23.1	5.2	12.4
Ohio Power Co.	BBB	4	56.5	58.3	59.5	3.4	22.1	4.7	16.1

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P			S&P Credit Stats					
					Average 2003-2005				
Name	Debt Rating	Business Profile	2005 Debt Ratio [1/]	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	Average ROE 2003-2005
Otter Tail Corp.	BBB+	8	36.6	50.5	53.2	3.7	24.3	4.4	12.2
Pacific Gas & Electric Co.	BBB	5	57.0	60.4	59.0	2.6	26.4	3.2	30.1
PECO Energy Co.	BBB+	4	73.6	48.3	52.7	5.7	65.0	11.5	45.3
Pennsylvania Electric Co.	BBB	4	35.6	36.1	35.1	2.2	11.4	3.0	2.1
Pennsylvania Power Co.	BBB	6	40.6	41.3	39.8	9.1	53.4	10.9	18.6
PEPCO Holdings Inc.	BBB	5	60.1	64.0	65.1	2.1	12.1	3.0	7.4
Pinnacle West Capital Corp.	BBB-	6	46.8	57.5	60.3	2.5	16.5	3.6	7.6
PNM Resources Inc.	BBB	6	61.6	65.9	60.7	2.2	18.0	4.5	6.5
Portland General Electric Co.	BBB+	5	42.6	52.8	51.3	2.2	24.0	4.1	5.8
Potomac Electric Power Co.	BBB	3	55.5	52.2	54.7	2.8	21.8	4.2	11.8
PPL Corp.	BBB	7	62.3	66.8	69.3	2.7	18.2	4.0	20.0
Progress Energy Inc.	BBB	5	57.8	62.3	61.6	2.0	12.7	3.1	10.1
PSEG Power LLC	BBB	8	55.4	55.4	55.3	6.9	22.3	8.4	13.8
PSI Energy Inc.	BBB	4	57.1	57.6	56.2	3.7	15.4	4.5	9.7
Public Service Co. of Colorado	BBB	4	47.3	54.7	57.5	2.4	16.2	3.5	9.8
Public Service Co. of New Hampshire	BBB	5	66.7	64.7	65.9	3.9	23.0	6.4	11.6
Public Service Co. of Oklahoma	BBB	5	54.0	57.2	57.1	2.5	19.1	3.7	10.1
Public Service Electric & Gas Co.	BBB	3	62.6	52.5	55.4	3.3	20.9	4.2	12.0
Public Service Enterprise Group Inc.	BBB	7	67.9	69.8	65.6	3.7	16.6	4.6	13.8
Puget Energy Inc.	BBB-	4	55.6	60.5	64.3	1.7	14.1	3.3	6.4
Puget Sound Energy Inc.	BBB-	4	56.1	60.5	62.8	2.0	15.2	3.1	8.0
Rochester Gas & Electric Corp.	BBB+	3	54.5	53.6	52.1	2.3	31.9	4.4	9.1
Sempra Energy	BBB+	7	49.2	53.5	53.3	3.7	27.9	5.0	19.3
Southern California Edison Co.	BBB+	6	48.2	58.4	58.3	3.9	37.8	5.8	19.0
Southwestern Electric Power Co.	BBB	5	50.9	54.4	56.1	2.9	24.1	4.5	11.7
Southwestern Public Service Co.	BBB	5	52.8	54.6	53.5	2.8	19.2	3.9	8.2
Tampa Electric Co.	BBB-	4	50.9	51.3	50.1	3.3	21.7	3.9	9.4
Toledo Edison Co.	BBB	6	27.1	52.6	60.9	2.3	12.6	3.5	6.5
Union Electric Co.	BBB	5	48.0	48.8	46.4	6.4	30.5	7.9	13.8
Union Light Heat & Power Co.	BBB	5	38.7	73.0	71.5	1.3	8.5	2.7	9.2
Virginia Electric & Power Co.	BBB	5	49.7	52.2	54.5	3.5	20.3	4.6	7.3
Western Massachusetts Electric Co.	BBB	1	68.3	64.5	60.7	3.1	18.7	7.4	9.0
Wisconsin Energy Corp.	BBB+	5	59.5	63.2	65.6	2.7	15.2	4.0	11.8
Xcel Energy Inc.	BBB	5	57.6	64.3	63.2	2.2	16.8	3.5	9.7
All BBB Rated Companies									
Mean	**BBB**	**5**	**52.3**	**56.4**	**57.5**	**3.1**	**20.9**	**4.5**	**11.1**
Median	**BBB**	**5**	**51.8**	**56.8**	**57.2**	**2.8**	**19.5**	**4.1**	**10.5**
BBB Subgroup Business Profile 1-4									
Mean	**BBB**	**3**	**55.6**	**55.5**	**56.2**	**2.9**	**20.8**	**4.2**	**11.6**
Median	**BBB**	**4**	**55.6**	**57.6**	**55.9**	**2.7**	**18.7**	**3.7**	**11.1**
BBB Subgroup Business Profile 1-5									
Mean	**BBB**	**3**	**52.8**	**56.3**	**56.7**	**3.2**	**21.4**	**4.6**	**11.2**
Median	**BBB**	**3**	**51.9**	**55.6**	**56.1**	**2.9**	**20.9**	**4.2**	**10.8**
BBB Subgroup Business Profile 5									
Mean	**BBB**	**5**	**51.5**	**57.6**	**58.0**	**3.1**	**20.4**	**4.6**	**10.8**
Median	**BBB**	**5**	**51.0**	**55.4**	**56.1**	**2.7**	**20.9**	**4.0**	**10.6**
BBB Subgroup Business Profile 6									
Mean	**BBB**	**6**	**50.1**	**57.1**	**58.5**	**3.1**	**21.4**	**4.6**	**10.7**
Median	**BBB**	**6**	**51.2**	**57.3**	**59.0**	**2.7**	**18.7**	**4.2**	**10.5**
BBB Subgroup Business Profile 7									
Mean	**BBB**	**7**	**55.8**	**60.5**	**60.9**	**3.3**	**21.9**	**4.3**	**14.2**
Median	**BBB**	**7**	**54.7**	**59.3**	**61.5**	**3.5**	**20.6**	**4.3**	**13.7**
BBB Subgroup Business Profile 7-10									
Mean	**BBB**	**8**	**51.7**	**54.7**	**57.2**	**3.4**	**21.1**	**4.5**	**12.3**
Median	**BBB**	**8**	**49.0**	**56.0**	**56.6**	**3.5**	**20.9**	**4.1**	**12.4**
Entire Sample									
Mean	**BBB**	**5**	**52.1**	**56.2**	**57.1**	**3.2**	**21.4**	**4.6**	**11.3**
Median	**BBB**	**5**	**51.7**	**56.6**	**56.8**	**2.9**	**20.7**	**4.2**	**10.9**

1/ Sum of long- and short-term debt divided by the sum of long-term debt, short-term debt, common equity and preferred stock.

Source: Standard and Poor's Research Insight and Credit Stats.

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF HIGH GENERATION US ELECTRIC UTILITIES

	Total Assets ($millions)	Percent of Total Assets: Generation	Wires (2006)	Other	Nuclear Supply %	Nuclear Assets as % of Total Assets 1/	Value Line Beta	Research Insight Beta 2/	Common Equity Ratio 2006	S&P Debt Rating	S&P Business Profile	Moody's Debt Rating
Allete	1368	45.9%	41.6%	12.5%	0.0%	0.0%	0.90	1.02	63%	BBB+	6	Baa2
Ameren	21250	54.1%	40.5%	5.5%	13.0%	7.0%	0.75	0.60	50%	BBB-	7	Baa2
American Electric Power	37289	39.3%	59.9%	0.8%	9.0%	3.5%	1.35	1.00	40%	BBB	5	Baa2
Black Hills	1498	51.4%	21.8%	26.9%	0.0%	0.0%	1.10	0.85	50%	BBB-	8	Baa3
Constellation	20084	80.3%	19.7%	0.0%	52.0%	41.8%	0.95	0.72	47%	BBB+	7	Baa1
Dominion	45800	35.3%	28.5%	36.3%	20.5%	7.2%	1.05	0.69	39%	BBB	7	Baa2
DPL	4553	88.4%	10.6%	1.0%	0.0%	0.0%	0.95	0.98	28%	BBB	6	Baa3
DTE Energy	23762	34.9%	43.1%	22.0%	15.9%	5.5%	0.75	0.72	39%	BBB	6	Baa2
Empire District	1397	33.4%	65.0%	1.6%	0.0%	0.0%	0.85	0.81	46%	BBB-	6	Baa2
Entergy	30608	55.0%	45.0%	0.0%	55.9%	30.8%	0.90	0.52	46%	BBB	6	Baa3
FPL	34444	56.2%	43.8%	0.0%	24.1%	13.5%	0.85	0.69	45%	A	5	A2
Great Plains Energy	4318	51.8%	37.6%	10.6%	22.0%	11.4%	0.95	0.83	50%	BBB	7	Baa2
IDACORP	3310	44.8%	51.2%	4.0%	0.0%	0.0%	1.05	0.81	49%	BBB+	5	Baa2
Pinnacle	11456	40.9%	51.3%	7.8%	25.4%	10.4%	1.00	0.94	51%	BBB-	6	Baa3
PNM	5400	44.3%	55.7%	0.0%	23.7%	10.5%	0.95	0.96	40%	BBB	6	Baa3
PPL	19747	40.7%	59.3%	0.0%	30.0%	12.2%	0.95	0.57	39%	BBB	7	Baa2
Progress Energy	20881	46.1%	52.6%	1.3%	45.7%	21.1%	0.95	0.81	47%	BBB+	5	Baa2
Scana	8032	42.1%	49.6%	8.3%	19.0%	8.0%	0.85	0.70	43%	A-	4	A3
Southern Co.	43449	47.6%	47.9%	4.4%	15.0%	7.1%	0.70	0.33	41%	A	4	A3
Westar	5455	58.6%	41.4%	0.0%	16.0%	9.4%	0.95	1.12	47%	BBB-	5	Baa3
Wisconsin Energy	11399	48.9%	51.1%	0.0%	25.3%	12.4%	0.80	0.47	40%	BBB+	4	A3
Mean	**16928**	**49.5%**	**43.7%**	**6.8%**	**19.6%**	**10.1%**	**0.93**	**0.77**	**44.8%**	**BBB**	**6**	**Baa2**
Median	**11456**	**46.1%**	**45.0%**	**1.6%**	**19.0%**	**8.0%**	**0.95**	**0.81**	**45.8%**	**BBB**	**6**	**Baa2**
Weighted Average		**47.8%**	**44.2%**	**8.0%**	**24.6%**	**12.6%**	**0.93**	**0.68**	**43.0%**	**BBB+**	**6**	**Baa1**

1/ Nuclear Assets % of Total Assets = Total Generation % * Nuclear Supply % (excluding purchased power)

2/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

Source: Standard and Poor's Research Insight, Value Line (data downloaded July 13, 2007), www.Moodys.com and
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (July 24, 2007).

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF US WIRES UTILITIES

	Total Assets ($millions)	Total Gx %	Total Wires %	Other %	Value Line Beta	Research Insight Beta [1/]	Common Equity Ratio 2006	S&P Business Profile	S&P Debt Rating	Moody's Debt Rating
	(2006)									
Consolidated Edison	24584	2.9%	97.1%	0.0%	0.75	0.43	47.0%	2	A	A2
Energy East	11562	3.0%	94.3%	2.6%	0.95	0.69	41.0%	3	BBB+	Baa2
Nicor Inc.	4090	0.0%	92.8%	7.2%	1.30	0.99	50.7%	3	AA	Baa2
Northwest Nat. Gas	1957	0.0%	98.0%	2.0%	0.75	0.44	48.1%	1	AA-	A3
NSTAR	7769	2.6%	97.4%	0.0%	0.80	0.64	34.4%	1	A+	A2
Piedmont Natural Gas	2734	0.0%	97.2%	2.8%	0.80	0.60	47.0%	2	A	A3
Southwest Gas	3485	0.0%	96.1%	3.9%	0.85	0.51	38.9%	4	BBB-	Baa3
WGL Holdings Inc.	2791	0.0%	92.0%	8.0%	0.85	0.54	52.2%	3	AA-	A2
Mean	**7372**	**1.1%**	**95.6%**	**3.3%**	**0.88**	**0.60**	**44.9%**	**2**	**A**	**A1**
Median	**3788**	**0.0%**	**96.6%**	**2.7%**	**0.83**	**0.57**	**47.0%**	**3**	**A**	**A2**
Weighted Average		**2.2%**	**96.0%**	**1.8%**	**0.85**	**0.56**	**44.2%**	**2**	**A**	**A1**

[1/] Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.
[2/] WGL Holdings is Washington Gas Light

Source: Standard and Poor's Research Insight, Value Line (Data pulled July 13, 2007), www.Moodys.com and
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (July 24, 2007).

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electric Utilities								
AltaLink	7/04; 11/06	EUB	2004-052; U2006-292	67.00	0.00	33.00	8.51	4.22
ATCO Electric		EUB						
Transmission	7/04; 11/06		2004-052; U2006-292	61.00	6.00	33.00	8.51	4.22
Distribution	7/04; 11/06		2004-052; U2006-292	56.10	6.90	37.00	8.51	4.22
EPCOR		EUB						
Transmission	7/04; 11/06		2004-052; U2006-292	65.00	0.00	35.00	8.51	4.22
Distribution	7/04; 11/06		2004-052; U2006-292	61.00	0.00	39.00	8.51	4.22
FortisAlberta Inc.	7/04; 11/06	EUB	2004-052; U2006-292	63.00	0.00	37.00	8.51	4.22
FortisBC Inc.	3/06; 12/06	BCUC	G-14-06; L-75-06	60.00	0.00	40.00	8.77	4.22
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	6/06	IRAC	UE20934	57.31	0.00	42.69	10.25	na
Newfoundland Power	6/03;12/06	NLPub	PU 19(2003); PU 40(2006)	54.06	1.39	44.55	8.60	4.16
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na
Gas Distributors								
ATCO Gas	7/04; 11/06	EUB	2004-052; U2006-292	55.10	6.90	38.00	8.51	4.22
Enbridge Gas Distribution Inc	1/04; 7/07	OEB	RP-2002-0158; EB-2006-0034	61.33	2.67	36.00	8.39	4.23
Gaz Metropolitain	9/06	Régie	D-2006-140	54.00	7.50	38.50	8.73	4.55
Pacific Northern Gas	11/06; 5/07	BCUC	L-75-06; G-55-07	56.20	3.80	40.00	9.02	4.22
Terasen Gas	3/06; 12/06	BCUC	G-14-06; L-75-06	65.00	0.00	35.00	8.37	4.22
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23
Gas Pipelines								
Alberta Natural Gas	11/06; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.46	4.22
Foothills Pipe Lines (Yukon) Ltd.	11/06; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.46	4.22
TransCanada PipeLines	11/06; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.46	4.22
Trans Quebec & Maritimes Pipeline	11/06	NEB	RH-2-94	70.00	0.00	30.00	8.46	4.22
Westcoast Energy	11/06; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.46	4.22

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Electric Utilities																		
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	1/	1/	1/	1/	1/	1/	9.40	9.60	9.50	8.93	8.51
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	1/	2/	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**	**9.53**	**9.57**	**9.62**	**9.45**	**9.13**	**8.74**
Gas Distributors																		
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	9.62	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**9.08**	**8.59**
Gas Pipelines (NEB)																		
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.52**	**9.78**	**9.67**	**9.59**	**9.70**	**9.56**	**9.48**	**9.07**	**8.64**

Note: A rate freeze was in effect for BC Gas (now Terasen Gas) in 1990 and 1991, BCUC regulation resumed in late 1991.
Nova Scotia Power was privatized in 1992.

1/ Negotiated settlement, details not available.
2/ Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.66	10.69	2.97	12.69	8.61	4.08
1991	13.58	9.72	3.86	12.51	8.14	4.37
1992	12.99	8.68	4.31	12.06	7.67	4.39
1993	12.19	7.86	4.33	11.37	6.59	4.78
1994	11.54	8.69	2.85	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.88	6.66	4.22	11.34	6.58	4.76
1998	10.20	5.59	4.61	11.59	5.54	6.05
1999	9.52	5.72	3.80	10.74	5.91	4.83
2000	9.78	5.71	4.07	11.41	5.88	5.53
2001	9.67	5.77	3.90	11.04	5.50	5.54
2002	9.59	5.67	3.92	11.10	5.41	5.69
2003	9.70	5.31	4.39	10.98	5.03	5.95
2004	9.56	5.11	4.45	10.73	5.08	5.65
2005	9.48	4.38	5.10	10.50	4.52	5.98
2006	9.07	4.33	4.74	10.39	4.93	5.46
2007q2	8.57	4.26	4.31	10.30	4.90	5.40
Means:						
1990-1993	**13.10**	**9.24**	**3.87**	**12.16**	**7.75**	**4.41**
1994-1998	**11.22**	**7.42**	**3.80**	**11.41**	**6.62**	**4.80**
1999-2007q2	**9.44**	**5.14**	**4.30**	**10.80**	**5.24**	**5.56**

1/ 2007 ROE represents results for the entire year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; Federal Reserve; U.S. Treasury.

QUANTIFICATION OF IMPACT ON EQUITY RATIO REQUIREMENT TO EQUATE EQUITY RETURN FOR OPG'S REGULATED OPERATIONS TO THE ROE REQUIRED FOR BENCHMARK LOW RISK U.S. GAS & ELECTRIC UTILITIES
(Example at Mid-Point of Recommended Range)

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.0%[1]
Equity Cost	=	Cost of Equity [2]
	=	11.88%
Tax Rate	=	34.0%[3]

Average of Results Under the Two Approaches = 10.50%

THEORY 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity falls as leverage (debt ratio) decreases, but the $WACC_{AT}$ stays the same.
STEPS:

1. Estimate $WACC_{AT}$ at the benchmark common equity ratio of 45%

   $WACC_{AT}$ = (6.0%)(1-.34)(55%) + (11.875%)(45%)
   = 7.52%

2. Estimate Cost of Equity for sample at 55.0% common equity ratio with $WACC_{AT}$ unchanged at 7.35%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.52% = (6.0%)(1-.34)(42.5%)+(X)(57.5%)
   Cost of Equity at 55% Equity Ratio = 10.20%

THEORY 2:

After-Tax Cost of Capital Increases as Debt Ratio Decreases; Cost of Equity Declines
STEPS:

1. Estimate $WACC_{AT}$ at the benchmark common equity ratio of 45%

   $WACC_{AT}$ = (6.0%)(1-.34)(55%) + (11.875%)(45%)
   = 7.52%

2. Estimate $WACC_{AT}$ for 57.5% common equity ratio (LL - less levered)

   $WACC_{AT(LL)} = WACC_{AT(Benchmark)} x\ (1\text{-t x Debt Ratio}_{LL})/(1\text{-t x Debt Ratio}_{Benchmark})$

   $$WACC_{AT(LL)} = 7.52\%\ x\ \frac{(1-.34 \times 42.5\%)}{(1-.34 \times 55.0\%)}$$

   $WACC_{AT(LL)} = 7.91\%$

3. Estimate Cost of Equity at new $WACC_{AT}$ for less levered firm:

   $WACC_{AT(LL)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{LL}$) + (Equity Cost)(Equity $Ratio_{LL}$)
   7.91% = (6.0%)(1-.34)(42.5%) + (X)(57.5%)
   Cost of Equity at 57.5% equity ratio = 10.80%

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on Incremental Return Analysis, Appendix I
[3] Combined Federal/Ontario tax rate.

Yukon Electrical Company Limited

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
April 2008

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of, and a senior consultant with, Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, oil and gas pipelines, and telephone companies in more than 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Yukon Electrical Company Limited ("Yukon Electrical") has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity (ROE) for the Company's 2008 and 2009 test years, using, for the express purpose of these two test years, the benchmark return on equity established by the Alberta Energy and Utilities Board (EUB)[1] as a point of departure.

In that context, I have estimated the capital structure that would fully reflect the business risks of Yukon Electrical. Based on my analysis, the common equity ratio that would fully compensate for the business risks of Yukon Electrical lies at the upper end of a range of 47.5% to 52.5%.

At a common equity ratio of 52.5%, the allowed return on equity for Yukon Electrical should be equal to that applicable to an average risk Canadian utility, that is, a benchmark return on equity. For the express purpose of this proceeding, I recommend adopting the benchmark return on equity derived in the EUB's Generic Cost of Capital Decision 2004-052 (July 2, 2004), as adjusted for changes in interest rates. The benchmark return on

[1] Now the Alberta Utilities Commission or "AUC".

equity adopted by the EUB under its generic cost of capital automatic adjustment mechanism for 2008 was 8.75%, based on a long-term Canada bond yield of 4.55%.

With respect to the benchmark return on equity for test years 2008-2009, I recommend that the Yukon Utilities Board ("the Board"):

1. Adopt a single return on equity for both test years, based on the forecast average long-term Government of Canada bond yield of 4.5%; and,

2. Apply the EUB's automatic adjustment formula to arrive at a benchmark ROE for 2008-2009.

Since the forecast average long-term Government of Canada bond yield for 2008-2009, at 4.5%, is virtually identical to the forecast relied on by the EUB to determine the allowed ROE for 2008, the application of the automatic adjustment formula produces a benchmark return on equity of approximately 8.75% for 2008-2009. The indicated benchmark return on equity of 8.75% would be applicable to Yukon Electrical at a common equity ratio of 52.5%.

However, the benchmark ROE is viewed as below the level consistent with a fair and reasonable return. Thus, requiring shareholders to commit additional equity to achieve a 52.5% equity ratio to have the opportunity to earn a benchmark equity return regarded as too low is fundamentally incongruous. As a result, I recommend that the actual common equity ratio of Yukon Electrical be raised to 47.5% and to allow an incremental equity risk premium of 0.50% above the benchmark return on equity. The 0.50% incremental equity risk premium compensates for the difference in financial risk between the proposed 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a common equity ratio of 47.5%, the allowed ROE for Yukon Electrical should be set at 9.25%.

II. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN COST OF CAPITAL AND CAPITAL STRUCTURE

The cost of capital is largely a function of business risk, that is, the risks arising from the operations/assets of a firm. The cost of capital, however, is also a function of financial risk, i.e., additional risk borne by the common equity shareholder because the firm is using fixed obligation securities (e.g., long-term debt) to finance a portion of its assets. Therefore, the capital structure, comprised of fixed obligation securities and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used.

However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure <u>do</u> change. An increase in financial risk will accompany an increase in the cost of equity.

B. APPROACHES TO DETERMINING THE FAIR RETURN

Recognizing the relationship between the cost of capital and capital structure, there are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or benchmark. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an

adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines.[2] It is also the approach that was adopted by the EUB in its Generic Cost of Capital Decision. In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/EUB approach as long as the combination of actual/allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark return on equity. The combination of capital structures and equity risk premiums has also been used in Ontario and Québec.

For purposes of this proceeding, I have utilized the first approach and estimated the capital structure that is intended to fully reflect the business risks of Yukon Electrical. In other words, I have estimated a capital structure for Yukon Electrical, based on the principles set out in Section III that would be compatible with the application of a benchmark return on equity to Yukon Electrical. If, however, the common equity ratio

[2] In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002, 36% in 2005 and 40% in 2007.

adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

C. BENCHMARK RETURN ON EQUITY

1. Conceptual Considerations

Both approaches to determining a fair return outlined in Section II.B rely on the measurement of the equity return that would be applicable to a benchmark utility or average risk Canadian utility. That return will be referred to as a benchmark return on equity. A capital structure for Yukon Electrical would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return on equity; and (c) would equate the level of total (business and financial) risk faced by Yukon Electrical to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the common equity ratio for Yukon Electrical is established so that no adjustment to the benchmark return on equity is required.[3]

The term benchmark utility is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the benchmark utility reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve a particular debt rating,

[3] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." (Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999)

typically an A rating. The typical, average risk Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's (S&P).

Designation of a debt rating as an indicator of relative risk recognizes that (a) debt ratings reflect both business and financial risk, and (b) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would require lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return on equity.

For specific purposes of this proceeding, I recommend adopting as the benchmark return on equity, the generic return on equity applicable to the Alberta utilities as adjusted for any forecast changes in interest rates. The return on equity adopted by the EUB for 2008 was 8.75%, based on a forecast long-term Canada bond yield of 4.55%.[4]

2. Benchmark Return on Equity for Test Years 2008-2009

Expert testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Preparation of testimony, responses to information requests and cross-examination of witnesses entail a considerable amount of money, time and effort. As a result, the cost impact on a utility the size of Yukon Electrical can be

[4] Order 2007-0347, November 30, 2007.

significant. Yukon Electrical is proposing that for the specific purposes of this proceeding, the Alberta generic return on equity be used as a point of departure for establishing its allowed return on equity for the 2008-2009 test years, as adjusted for changes in interest rates. The generic return on equity established by the EUB in Decision 2004-052 and adjusted automatically each year in subsequent Orders is virtually identical to "benchmark" ROEs adopted by other Canadian regulators, including the National Energy Board and, implicitly, by the Public Utilities Board of the Northwest Territories when it established the allowed ROE for Northwest Territories Power Corporation in Decision 13-2007 (August 29, 2007). Using the EUB's generic return on equity as a point of departure, the costs associated with the determination of the allowed return on equity for Yukon Electrical should be greatly reduced. The cost of capital testimony can then focus on the issue of the capital structure that is required to fully compensate for the utility's business risks and, if necessary, given the specific financing considerations of the utility, any incremental equity risk premium relative to the benchmark return on equity that is required.

Given these considerations, I accept, for the express purposes of this proceeding, that the return on equity determined by the EUB in Decision 2004-052, as adjusted for changes in interest rates since the decision was issued, will be used as the basis for establishing the allowed return on equity for Yukon Electrical.[5] That return on equity, however, can only be applied to a common equity ratio that fully compensates for Yukon Electrical's business risks.

Decision 2004-052 established an automatic adjustment mechanism for determining a utility's allowed return on equity in response to a change in interest rates. Automatic adjustment mechanisms for determining a utility's allowed return on equity are relied

[5] In my opinion, as well as that of Yukon Electrical, the EUB benchmark return on equity is below the level commensurate with the comparable returns standard. The EUB as well as the NEB have initiated proceedings to determine whether their automatic adjustment mechanisms continue to produce a fair return. In the ATCO Utilities' view (with which I concur), as filed with the AUC on April 4, 2008, the automatic adjustment mechanism does not produce a fair return. Nevertheless, until such time as the issue has been reviewed by the AUC, Yukon Electrical is prepared to accept the EUB "benchmark" as a point of departure for establishing its allowed ROE for 2008 and 2009.

upon in six regulatory jurisdictions in Canada. The various mechanisms are all quite similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a base, or initial, return on equity and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base allowed return on equity are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula, or adjustment factor, to be used to adjust the allowed return on equity from one year to the next. The forecast yield on the long-term Government of Canada bond is used as the proxy for the risk-free rate.

Application of an adjustment mechanism like those used in most Canadian jurisdictions requires the following steps:

Step 1: Establish the forecast long-term Canada bond yield for the test year(s),

Step 2: Apply the adjustment factor to the difference between the test year forecast(s) of the long-term Canada bond yield and the bond yield underlying the base allowed return on equity, and

Step 3: Adjust the base allowed return on equity by the amount(s) determined in Step 2.

In five of the six Canadian jurisdictions that currently use an automatic adjustment mechanism,[6] the adjustment factor is set at 0.75, i.e., the change in allowed return on equity equals 75% of the change in the forecast long-term Government of Canada bond yield. The 75 basis point change in allowed return on equity for every one percentage point in the forecast long term Government of Canada bond yield reflects some

[6] The five regulatory boards that use automatic adjustment mechanisms with a 0.75 adjustment factor are the EUB, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board, and the Régie de l'Energie de Québec. In Newfoundland and Labrador, the adjustment factor is 0.80.

recognition that the return on equity does not move in tandem (one for one) with changes in the yield on long-term government bonds.[7]

As indicated in Section II.C.1 above, the 2008 Alberta generic return on equity is 8.75% (at a long-term Canada bond yield of 4.55%). Yukon Electrical is proposing rates for a two-year test period, 2008-2009. I recommend that the PUB adopt a single benchmark return on equity for both test years, based on the average forecast long-term Government of Canada bond yield during the test years.

The most recent Consensus Economics, *Consensus Forecasts* (April 2008) indicates that the 10-year Government of Canada bond yield will be 3.6% in July 2008 and 3.9% by April 2009. During the first four months of 2008, the 10-year Government of Canada bond yield averaged approximately 3.7% (and the 30-year Government of Canada bond yield averaged 4.1%). Based on the actual yields to date and the *Consensus* for July 2008 and April 2009, the 10-year Government of Canada bond yield is forecast at approximately 3.7%. During April 2008, the spread between 10 and 30 year Canada bond yields averaged approximately 50 basis points. The addition of 50 basis points to the forecast 10-year bond yield produces a forecast 30-year Canada bond yield of 4.2% for 2008.

There is no consensus forecast for all of 2009. However, the long-term forecast for 10-year Government of Canada bond yields contained in the April 2008 Consensus Economics, *Consensus Forecasts* anticipates that the 10-year Government of Canada bond yield will be 5.0% in 2010. In the absence of a 2009 consensus forecast for Canada, the quarterly consensus forecasts for U.S. 10-year Treasury bond yields can be used to approximate the forecast for the 10-year Government of Canada bond yield, as the available consensus forecasts show that the Canadian and U.S. rates are expected to track

[7] While the 0.75 adjustment factor recognizes to some extent the inverse relationship between equity risk premiums and equity returns, it overstates the extent to which they move together. Nevertheless, to the extent that the automatic adjustment formula has reduced allowed ROEs since the inception of such formulas, it is reasonable for the formula to increase allowed ROEs by a similar amount until such time as a benchmark return is recalibrated and, if warranted, a new formula established.

closely, with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010. The Blue Chip *Financial Forecasts* (May 1, 2008) anticipates that the 10-year U.S. Treasury yield will increase quarterly by 0.10% during 2009. The resulting 10-year 2009 Government of Canada bond yield would be approximately 4.2%. Based on these forecasts and a continuation of the current 50 basis point spread between 10- and 30-year Canada bond yields, I anticipate that the 30-year Canada bond yield will average 4.7% in 2009.

The average forecast 30-year yield for the two test years is thus approximately 4.5%, similar to the 4.55% forecast relied on by the EUB to set the Alberta "benchmark" return of 8.75%. While the 2008-2009 average forecast long-term Canada bond yield of 4.5% is somewhat higher than the forecast for 2008 alone, Yukon Electrical is taking the risk that the actual long-term yields in 2009 will be higher than currently anticipated.

Based on a 4.5% long-term Canada bond yield forecast, the benchmark return on equity (ROE) for Yukon Electrical's 2008-2009 test years is approximately 8.75%, the same as the 2008 Alberta generic return on equity.

I recommend, therefore, that a benchmark return on equity of 8.75% be adopted for both test years; the 8.75% would be applicable to the common equity ratio estimated in Sections III to VIII. If, however, the common equity ratio adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

III. PRINCIPLES FOR CAPITAL STRUCTURE

The following principles should be respected when establishing the appropriate capital structure for Yukon Electrical:

A. The Stand-Alone Principle.
B. Compatibility of Capital Structure with Business Risks.
C. Maintenance of Creditworthiness/Financial Integrity.

Each of these principles is defined below.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by Yukon Electrical should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

Yukon Electrical is 100% owned by ATCO Electric. ATCO Electric, in turn, is a wholly-owned subsidiary of CU Inc. Yukon Electrical operates as a stand-alone entity (separate from the other electric utility operations of ATCO Electric). CU Inc. raises debt on behalf of Yukon Electrical. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities, including Yukon Electrical, at the cost incurred by CU Inc. Yukon Electrical's customers, therefore, receive the benefits of CU Inc.'s ratings. In turn, Yukon Electrical should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the benefits of debt costs that reflect an A(high)/A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

Based on the indicated spreads for new issues as published by RBC Capital Markets, CU Inc. has been able to raise new 30-year debt on average at approximately 120 basis points over a similar term Government of Canada bond during 2007 and the first quarter of 2008. Over this period, spreads for utilities with one debt rating in the BBB category (split-rated utilities) have ranged from 135 basis points (Union Gas rated A by DBRS and BBB+ by S&P) to 175 basis points (EPCOR Utilities, rated A(low) by DBRS and BBB+ by S&P) and have averaged approximately 140-145 basis points (See Schedule 1).

The 2007-2008Q1 average masks the widening spreads over the period. As investors have become more risk-averse, and the outlook for the economy has deteriorated, credit spreads have widened considerably since the end of 2006. At the end of March 2008, the indicated spread for a new 30-year CU Inc. issue was 157 basis points versus 92 basis points at the end of 2006. Spreads for new split-rated A/BBB issues have increased from approximately 125-130 basis points to 200 basis points over the same period.

Depending on the state of the capital markets, the spread between the cost of a new long-term debt issue for a strong A credit and one for a split A/BBB credit can be much higher than it is currently. As recently as five years ago, the spread has been as high as 100 basis points.

With respect to electric power corporations that are still investment grade but rated in the BBB category by all the debt rating agencies, there is only one conventional equity corporation (i.e., non-income trust) included in the S&P/TSX Utilities Sector, TransAlta Corporation. The average indicated spread for a new 30-year TransAlta Corporation debt issue during 2007-2008Q1 has been 278 basis points; at the end of March 2008, the spread was 390 basis points. (Schedule 1) The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long term debt of approximately 233 basis points provides a perspective on the potential magnitude of the benefits to ratepayers of Yukon Electrical's affiliation with CU Inc. As a true stand-alone entity, Yukon Electrical would not be able to obtain investment grade debt ratings given its small size. The estimation of an appropriate capital structure for Yukon Electrical should recognize the magnitude of the cost benefits conferred upon ratepayers arising from Yukon Electrical's ability to access debt capital through CU Inc. rather than on its own.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

For larger utilities like CU Inc. which regularly access the public debt markets, a reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult or weak capital market conditions.

As noted above, Yukon Electrical is too small to have its own debt ratings (i.e., it would not be investment grade) or to access the public debt markets on its own. If it were to access third-party debt on its own, its options would be limited to banks or insurance companies at a significantly higher cost than is available to CU Inc., and with more stringent covenants. A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to Yukon Electrical both the actual cost of debt that Yukon Electrical would be able to obtain on its own and the capital structure that would be required by a potential lender to provide debt capital in the absence of its affiliation with CU Inc.

To my knowledge, the only small (total capital less than $100 million) regulated company that has accessed debt on a true stand-alone basis within the past five years is Natural Resource Gas (NRG), a small Ontario natural gas distributor. NRG was able to obtain five-year bank financing during 2005, a period of easy credit, at a spread over five-year Government of Canada bond yields of approximately 280 basis points. At the same time, the larger gas utilities (with debt ratings in the A/BBB rating categories) were able to issue five-year debt at spreads of 40-45 basis points over five-year Government of Canada bond yields. At the time, TransAlta Corporation was able to raise five-year debt at approximately 70 basis points above a similar term Government of Canada bond yield. While NRG is somewhat smaller (assets of approximately $9 million) than Yukon Electrical, it would be of reasonably similar business risk to Yukon Electrical. Thus NRG's stand-alone cost of debt provides a further indicator of the order of magnitude of the benefit that Yukon Electrical's ratepayers receive as a result of Yukon Electrical's affiliation with CU Inc.

My assessment of the appropriate capital structure for Yukon Electrical balances the stand-alone and creditworthiness and financial integrity principles with a recognition that the impact of small size on lenders' willingness to lend funds and on the stand-alone cost of debt would be, in part, related to the lack of liquidity and institutional interest in small debt issues rather than to fundamental business risk factors. Nevertheless, the appropriate capital structure and return on rate base for Yukon Electrical needs to recognize the cost benefits that Yukon Electrical's ratepayers receive.

IV. BUSINESS RISK

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short-term and long-term risks. Long-term risks are important because utility assets are long-lived. Moreover, utility stocks are not typically purchased as short-term investments. Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall higher return rewards when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future.

Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

Market demand risk relates to those factors that can lead to annual volatility in electricity sales or loss of customers. It includes market size, economic diversity and strength of the service area, growth potential, concentration of sales, competition with alternative energy sources and weather.

Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity. The physical risks of the utility are a function of its geography, mix of generation and ability to access alternative sources of supply.

The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed.

The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

Yukon Electrical is a small integrated electric utility serving 19 communities and approximately 15,000 customers spread throughout the territory. Whitehorse, the largest community, accounts for over 70% of the population of the Yukon. The largest community served outside of Whitehorse is Watson Lake, with a population of approximately 1,600. The populations of the other communities served range from approximately 10 to 300. Total sales in 2007 were approximately 300 GW.h. To put this in perspective, the following table compares customers, sales, and rate base of major Canadian investor-owned and government-owned electric utilities with rated debt, i.e., not guaranteed.[8]

Table 1

Company	Customers	Sales (GW.h.)	Rate Base ($ Millions)
Yukon Electrical	15,000	300	43
Electric Utilities with Rated Debt:			
ATCO Electric	216,000	10,300	1,500
EPCOR Utilities	318,000	7,100	500
FortisAlberta	430,000	14,700	800
FortisBC	152,000[1/]	3,100	680
Hydro One	1,300,000	29,300	8,400
Hydro Ottawa	280,000	7,500	500
Maritime Electric	66,000	1,000	200
Newfoundland Power	229,500	5,000	750
Nova Scotia Power	460,000	11,600	2,900

[1/] Includes both direct (approximately 100,000) and indirect customers.

[8] For comparison with other northern electric utilities:

Company	Customers	Sales (MW.h.)	Rate Base ($ Millions)
NTPC[1/]	18,800	310,000	200
NU (YK)	7,900	157,000	20
NU (NWT)	2,600	35,000	12
YEC[1/ 2/]	15,000	302,000	158

[1/] Includes both direct and indirect customers.
[2/] Rate base approximated by 2006 net property, plant and equipment.

As the table above indicates, Yukon Electrical is approximately one-quarter the size of the smallest utility (Maritime Electric) with its own debt ratings. Growth in rate base has been relatively strong over the past 10 years (approximately 3% annually). Future growth is expected to come from growth in new residential and commercial development and the continuing replacement of aerial infrastructure, i.e., exposed distribution lines, with underground lines. While rate base growth is expected to remain relatively strong, Yukon Electrical is expected to remain a very small utility relative to its Canadian peers. From a business risk fundamentals perspective, small size limits a utility's ability to diversify its risks geographically, operationally and among services provided.

Yukon Electrical's customer profile, based on 2007 actual data, is as follows:

Table 2

	Residential	**Commercial and Secondary[1/]**	**Street & Sentinel Lighting**	**Wholesale**
Sales ($000)	$14,088	$20,182	$837	$53
Customers	12,452	2,592	na	1

[1/] The majority of customers (2,570) and sales ($18,728) are commercial.

While Yukon Electrical currently has no industrial customers of its own, the economic base of the Yukon will have secondary impacts on the residential and commercial customer load. The cornerstones of the economy of the Yukon have historically been resource-based industries. The impact of these industries (principally mining) on the economy of the Yukon declined over the past decade following the closure of the Faro Mine in January 1997.[9] Prior to the mine's closure, the mining and oil and gas extraction industries had accounted for approximately 12% of GDP. In 2006, the portion of GDP accounted for the mining/oil and gas industries had fallen by half, to approximately 6% (virtually all of which is accounted for by gold mining). The opening of the new Minto

[9] The mine was operated by Anvil Range Mining at the time of its closure.

Mine in late 2007[10] is expected to have a positive impact on the economy, but will correspondingly increase the potential volatility in the economic performance of the Yukon.

The largest sector of the Yukon economy is public administration (government) contributing approximately 24% of GDP in 2006. This sector has a moderating impact on the territory's economy, because its rate of growth, while exhibiting some variability, is not subject to the wide swings seen in some other sectors, e.g. the resource-based sectors, manufacturing and construction. The importance of government to the economy of the Yukon is reflected in Yukon Electrical's customer profile/sales margin. Of Yukon Electrical's 18 largest customers, 11 are government-related entities, accounting for 17% of gross margin. Despite the moderating effect of government, annual GDP growth rates in the Yukon have been volatile, in part due to the year to year changes in construction activity. Over the 1998-2006 periods, annual GDP growth in the Yukon has been approximately twice as volatile as that of the individual provinces.

The divergent rates of growth in the Yukon over time demonstrate the volatility in the economy and potential impact on Yukon Electrical. Not only do the actual annual rates of growth exhibit considerable volatility, there can be significant differences between rates of growth as initially reported or forecast and the final actual rates of growth once all revisions have been made. For example, in May 2007, the Yukon Government, in its *Yukon Economic Overview and Outlook 2007* reported a 2005 rate of real GDP growth of 5.2%. The actual rate, as indicated above, was only 3.9% when revised in November 2007. The potential variance between forecast and actual rates of growth enhances Yukon Electrical's forecasting risk. On the cost side, forecasting risks are further increased by the tight labour market, particularly for skilled workers, rising wages and rising costs of basic materials.

[10] The mine is expected to connect to Yukon Energy in late 2008 and generate approximately 40 MW.h of sales. The costs associated with extending the transmission line to the mine are being paid by Minto Explorations Inc., the mine operator, and the Territorial Government.

Electric utilities, including Yukon Electrical, are subject to the risk of lost sales arising from the increasing emphasis on energy efficiency, conservation and reducing peak load. Lost load due to energy efficiency and conservation efforts reduces the utility's earnings. The implementation of energy conservation and efficiency initiatives, with the objective of reducing energy costs and environmental impacts raises the risk to earnings.[11] The Yukon Government is actively promoting energy efficiency through its Energy Solutions Center. Moreover, the elimination of Yukon Energy's Rate Stabilization Fund will act as an incentive for conservation.

With respect to supply and physical risks, Yukon Electrical faces a significantly higher level of risk relative to other Canadian electrical utilities. The electric utility network in the Yukon has two main grids: the Whitehorse/Aishihik/Faro (WAF)[12] and the Mayo/Dawson grid.[13] The WAF grid is fed by Yukon Electrical's Fish Lake hydroelectric facility and Yukon Energy's Aishihik and Whitehorse hydroelectric plants. Yukon Electrical has backup generation to the WAF grid through its diesel standby plants at Carmacks, Ross River, Haines Junction/Canyon Creek and Teslin. Yukon Electrical's diesel plant at Stewart provides backup generation capacity to the Mayo/Dawson Grid. Yukon Electrical also serves a number of isolated communities (not connected to the grid) in the Yukon with diesel generation (Watson Lake, Beaver Creek, Destruction Bay/Burwash Landing, Old Crow, Pelly Crossing and Swift River). Pelly Crossing is forecast to be connected to the WAF grid in the 4th quarter of 2008.

Approximately 12% of Yukon Electrical's rate base is comprised of generation assets (approximately 90% of which is diesel). The presence of generation assets in rate base generally increases the business risk of Yukon Electrical relative to a pure distribution utility, as the operational risks associated with generation exceed those of "wires" operations. In the case of Yukon Electrical, the operating risks are exacerbated by the

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[11] A number of regulatory jurisdictions in North America have implemented or are investigating revenue decoupling (decoupling revenues from consumption) to address this issue.

[12] The WAF grid connects Whitehorse with Yukon Electrical's franchise communities of Carcross, Carmacks, Haines Junction/Canyon Creek, Ross River and Teslin.

[13] The Mayo/Dawson grid connects Yukon Electrical's franchise communities of Stewart Crossing and Keno Hill with Yukon Energy's franchise communities of Dawson City, Elsa and Mayo.

severe climate in which the utility operates, increasing both the risk of outages and the potential unanticipated impacts of repair (in terms of both time and expenditures), and the isolated nature of some of the smaller communities served. While Yukon Electrical has proposed deferral accounts that cover diesel fuel costs, the high cost of diesel fuel creates an additional incentive to conserve energy (thus leading to lower than expected sales). Further, in contrast to hydroelectric generation, diesel generation is exposed to greater risks of complying with increasingly stringent environmental standards. Yukon Electrical has a significant amount aerial infrastructure, i.e., exposed distribution line. Although the exposed lines are being moved underground, the exposed lines, in conjunction with a heavily treed service territory, increases the operating risks of Yukon Electrical.

With respect to regulatory risk, as independent tribunals, regulators have the power to expose utilities to relatively high risks, by, for example, disallowing costs, approving rate designs that are tilted against recovery of fixed costs, or returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility an opportunity to achieve a fair return with a reasonably high probability. This explains why regulation is considered to be a key element of a utility's business risk profile. On balance, the regulatory environment in the Yukon has been even-handed and reasonable in its approach; the Board has granted deferral accounts for costs that are beyond the control of management, including power costs, diesel fuel and generation costs, plant maintenance expense and rate case expense.[14] Nevertheless regulatory decisions can also have a negative impact on utilities.

Ms. McShane has no reason to conclude that, based on current policies and practice, that Yukon Electrical, similar to other regulated utilities in North America, will not be provided a reasonable opportunity to recover its capital investment. Nevertheless, the

[14] The existence of these deferral accounts does not constitute a guarantee that the costs accrued in the account will be recoverable from customers.

regulator cannot provide a guarantee that the capital investment will be recovered. The regulator can not provide a guarantee that long-term economic conditions will permit the full recovery of the invested capital, it does not make energy policies that can favor the government-owned utility and/or impact on the ability to recover the invested capital, and it cannot bind the decisions of future regulators.

On balance, as a very small utility operating in a service territory with an undiversified economic base and facing significant geographic physical/operating challenges, Yukon Electrical:

- is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada,
- is of higher than average business risk within the spectrum of Canadian utilities and,
- is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited.

V. CAPITAL STRUCTURES OF PEERS

The determination of the capital structure that reflects Yukon Electrical's business risks and would be compatible with the application of the benchmark return on equity requires comparisons with the capital structures of other electric utilities for two reasons. First, electric utilities which raise debt in the public markets (and, therefore, have debt ratings) have capital structures that have been "tested" by the capital markets. Thus, their capital structures, in conjunction with other key financial metrics (e.g., coverage ratios), provide an indication of the capital structure required to maintain investment grade debt ratings. Second, the common equity ratios allowed for other electric utilities (whether or not their debt is rated), either through regulatory decisions or settlements, provide a measure of the level that is warranted for an electric utility to compete for capital with its peers, with due regard to differences in business risk.

Table 3 below sets out the average actual common equity ratios of Canadian electric utilities with rated debt, as well as those of low risk U.S. electric utilities with debt rated in the A category.

Table 3

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	43.4%
Transmission & Distribution	A/Baa1/A-	44.5%
Integrated	A(low)/Baa2/BBB+	40.5%
U.S. A-rated Electric Utilities	na/A2/A	49.0%

Source: Schedules 2, 3 and 4.

Table 3 indicates that the average actual common equity ratios for all Canadian electric utilities with rated debt and for Canadian transmission and distribution utilities have averaged close to 43.5% and just below 45% respectively. The corresponding debt ratings by all three debt rating agencies have been, on average, approximately A-/A(low).

Given Yukon Electrical's higher than average business risks, the equity ratios maintained by other Canadian electric utilities indicate that a 45% common equity ratio would be too low to fully compensate for its business risks. Two of the smaller investor-owned primarily electric distribution utilities that would be considered the closest comparators to Yukon Electrical of the Canadian electric utilities with rated debt (Maritime Electric and Newfoundland Power) both have target actual common equity ratios of 45%. While they are the closest comparators, both are significantly larger and face lower business risk than Yukon Electrical. Moreover, their allowed returns on common equity are higher than the returns allowed under the Alberta formula which serves as the benchmark return on equity for Yukon Electrical.[15] These specific "comparators" strengthen the conclusion

[15] Maritime Electric, which is not subject to an automatic adjustment formula, was allowed a common equity return of 10.0% for the 2008 test year, approximately 125 basis points higher than the EUB's generic

that a 45% common equity ratio for Yukon Electrical (at the benchmark return on equity) is too low to fully compensate for Yukon Electrical's business risks. With respect to the recent Northwest Territories Power Corp. (NTPC) decision, for the 2007/08 test year, the Public Utilities Board of the Northwest Territories adopted a common equity ratio of 48.86% and an incremental equity risk premium of 0.50% for NTPC, a higher business risk utility than Yukon Electrical. The corresponding equity ratio for NTPC that would fully compensate for its higher business risks would be approximately 56-57%. Since NTPC faces higher business risk than Yukon Electrical, the fully compensatory equity ratio for Yukon Electrical indicated by the NTPC decision would be lower than 56-57%.

As the capital market has become increasingly global, Canadian utilities increasingly find themselves competing with foreign utilities for financing. The similarities and proximity of the U.S. and Canadian capital markets make comparisons with U.S. electric utilities especially relevant. The major bond rating agencies increasingly draw comparisons between Canadian utilities and their U.S. peers. Thus, the capital structures of U.S. electric utilities of reasonably similar business risk to Yukon Electrical and with debt rated in the A category may provide some guidance.

Since 1999, S&P has assigned to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest.[16] As of November 2007, the median business profile score of the U.S. electric utilities with debt rated in the A category was "4".[17] By comparison the average S&P business profile score assigned to Canadian utilities has been "3". Like Yukon Electrical, the majority of these companies are largely "wires" or "pipes" companies.[18] However, as discussed in

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return on equity for the same test year. Newfoundland Power's allowed return on equity at a 4.55% long-term Government of Canada bond yield would be 8.91%.

[16] The key qualitative factors that S&P evaluates in assessing the business risk of regulated electric utilities include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness.

[17] In November 2007, S&P integrated its utility business/financial risk evaluation methodology into its broader corporate ratings matrix and no longer provides as detailed or transparent a matrix for utilities.

[18] Newfoundland Power, for example, was assigned a business risk profile score of "3". Newfoundland Power would be considered to face lower business risks than Yukon Electrical, given its size, service area and more comprehensive slate of deferral accounts, including revenue protection against weather variations.

Section IV, Yukon Electrical would be viewed as facing higher business risks than the typical Canadian utility. On balance, based on its business risk fundamentals, Yukon Electrical would, on a stand-alone basis, be assigned a business profile score within the "4" category, higher than the typical Canadian utility, but the same as the A rated U.S. utilities.

The higher business risk of the U.S. electric utilities relative to the typical Canadian electric utility is reflected in their higher common equity ratios, leading to similar debt ratings. As indicated in Table 3 above, the median 2006 actual common equity ratio of U.S. electric utilities with debt rated in the A category was 49.0%. Given the similarity in the level of business risks between the A rated U.S. electric utilities and Yukon Electrical, in isolation,[19] the 49% median equity ratio is a reasonable benchmark for Yukon Electrical.

With respect to allowed common equity ratios, Table 4 below summarizes the most recently adopted capital structures for major Canadian electric utilities, along with any applicable incremental equity risk premiums. Unlike Yukon Electrical, both NTPC and Yukon Energy are government-owned utilities whose debt is guaranteed by their respective Territorial governments. However, like Yukon Electrical, they are both northern utilities, and they are both largely treated like investor-owned utilities for purposes of establishing capital structure and return on equity.

[19] As discussed in more detail in Section VII, the debt ratings of utilities in a particular business risk category are not solely driven by capital structures. They are also driven by other financial parameters, including coverage ratios. Coverage ratios are a function of cash flows, which, in turn, are dependent upon equity returns. The common equity return for the A rated U.S. electric utilities has averaged 11.8% over the past three years (2004-2006), compared to the 8.75% benchmark return. Taking the actual common equity ratios and ROEs of the A rated utilities together, a 50% common equity ratio for Yukon Electrical at the benchmark 8.75% ROE would be too low to equate Yukon Electrical to a benchmark utility.

Table 4

Alberta Taxable Distributors	37.0%
FortisBC	40.0% (plus 0.40% risk premium above BCUC's low risk utility benchmark)
Maritime Electric	42.7% (ROE has been approximately 1.25% higher than Canadian average)
Newfoundland Power	44.5% (risk premium 0.15% higher than benchmark)
Northwest Territories Power	48.6% (plus 0.50% risk premium)
Nova Scotia Power	37.5% (ROE approximately 0.75% higher than Canadian average)
Ontario Electric Distributors	40.0%
Yukon Energy	40.0% (plus 0.52% risk premium above BCUC's low risk utility benchmark) [1/]

[1/] Equal to average of the incremental equity risk premiums of Pacific Northern Gas (65 basis points) and FortisBC (40 basis points); by Order in Council, Yukon Energy's return on equity is then reduced from the "fair return on common equity" by 0.50%.

Source: Schedule 5.

If the capital structure for each of the utilities in Table 4 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47%. On average the companies included in Table 4 are of lower business risk than Yukon Electrical. On this basis, the common equity ratio for Yukon Electrical necessary to compensate for its business risks would be higher than 46-47%.

With respect to U.S. electric utilities, since the beginning of 2005, the average common equity ratio adopted for ratemaking purposes has been 47.9%.[20] The average business profile score of all U.S. electric utilities rated by S&P is "5". Thus, the business risk of the U.S. electric utility industry as a whole is higher than that of Yukon Electrical. However, the average debt rating of all U.S. electric utilities is only BBB. Consequently, it may be inferred that a common equity ratio of 47.5% is not adequate for a "5" business profile score and an A credit rating. Given Yukon Electrical's lower fundamental business risks than the U.S. industry in the aggregate, but higher target debt rating (in the A category), the U.S. electric industry average allowed common equity ratio suggests that

[20] Regulatory Research Associates, *Major Rate Case Decisions, January–March 2008*, April 2, 2008. Allowed returns on equity have averaged 10.4% over the same period.

a 47.5% common equity ratio would constitute a floor for the equity ratio required to equate Yukon Electrical to the benchmark utility.

On balance, the actual and allowed equity ratios of other Canadian electric utilities, and those of U.S. electric utilities (in conjunction with their actual and allowed ROEs) indicate that the common equity ratio required to fully compensate for Yukon Electrical's business risks would be no less than 47.5%.

VI. RATING AGENCY DEBT RATIO GUIDELINES

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), S&P has published the most detailed matrix of quantitative guidelines for different debt ratings.[21] For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds From Operations (FFO)[22] Interest Coverage, and FFO to Total Debt (discussed in Section VII). S&P does not apply their guidelines mechanistically; however, the guidelines do represent one objective basis for evaluating an appropriate stand-alone capital structure for Yukon Electrical.

S&P's debt ratio guidelines for an A debt rating and a business risk score of "4", the notional business risk score attributed to Yukon Electrical, are as follows:

Table 5

Total Debt/Total Capital	45.0-52.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

The guidelines for a business risk profile score of "4" indicate that a common equity ratio in the range of 48% to 55% (mid-range of 50.0-52.0%) is warranted for an A rating.

[21] DBRS has published guidelines, but the guidelines have not distinguished by either business risk or investment grade rating category.
[22] FFO means Funds from Operations, which equal net income plus non-cash items, including depreciation, deferred taxes and other non-cash expenses, e.g., amortization of regulatory assets.

Moody's also has published quantitative guidelines. As with S&P, other factors may outweigh the mechanistic application of the guidelines in determining a rating. However, the guidelines provide "broad guidance on the ratio ranges that may generally be seen at different rating levels".[23] While neither Yukon Electrical nor CU Inc. has a Moody's rating, there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's. Thus Moody's guidelines are applicable to those companies and, in turn, will play a role in the formation of target capital structures among Canadian utilities, with the objective of maintaining investment grade debt ratios.

Canadian distribution utilities are typically considered to be operating in a "low business risk" environment by Moody's due to the high degree of regulation and a supportive regulatory system. However, due to its specific business risk fundamentals and small size, Yukon Electrical would likely be classified within the "medium business risk" category. Moody's debt ratio guidelines for an A rating for a regulated company of "medium risk" are:

Table 6

Debt/Capital	40.0-60.0%

Source: Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

Based on Moody's debt ratio guidelines, a reasonable common equity ratio for Yukon Electrical compatible with a stand-alone A rating would be in the middle of the range, i.e., approximately 45%-55%.

The S&P and Moody's debt ratio guidelines, taken together, support a common equity ratio of approximately 45%-55% (mid-point of 50%).

[23] Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005, page 8.

VII. RATING AGENCY GUIDELINES OTHER THAN DEBT RATIO

Based on the actual and allowed equity ratios for other Canadian and low risk U.S. electric utilities (Section V), the rating agency debt ratio guidelines (Section VI) and consideration of Yukon Electrical's relative business risk (Section IV), a common equity ratio range of 47.5%-52.5% (mid-point of 50%) would be required to equate Yukon Electrical to the benchmark utility (i.e., one with a credit rating of A).

However, the common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Both S&P and Moody's consider cash flow coverage ratios to be key quantitative financial metrics, specifically FFO Interest Coverage and FFO/Total Debt. If a utility is able to achieve adequate cash flow coverage ratios, despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of return on equity, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's and Moody's guideline ranges for the debt ratio, while an important indicator of an appropriate capital structure, should be referenced with regard to other financial metrics.

Table 7

	S&P	**Moody's**
	"4"	"Medium Risk"
FFO Interest Coverage	3.5-4.2X	3.5-6.0X
FFO/Average Total Debt	20.0-28.0%	22.0-30.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006 and Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

I have estimated the FFO Interest Coverage and FFO/Total Debt ratios for Yukon Electrical based on common equity ratios of 47.5% and 52.5%. Specifically, I estimated the ratios using capital structures containing 47.5% and 52.5% equity, each in conjunction with a benchmark return on equity of 8.75%, Yukon Electrical's forecast embedded cost of debt of 6.83% and forecast depreciation expense for 2009. In interpreting the results, it is important to recognize, as noted earlier, that the guidelines are not applied mechanistically.

Yukon Electrical's indicated FFO Interest Coverage ratios are 4.2X and 4.7X at 47.5% equity and 52.5% equity respectively. The indicated ratios are at the upper end of S&P's guideline range at a 47.5% common equity ratio and above the upper end of the range at a 52.5% common equity ratio. In each case, the calculated FFO coverage ratio is below the mid-point (4.75X) of Moody's guideline range. The estimated FFO/Total Debt ratios (22% and 25% at common equity ratios of 47.5% and 52.5% respectively) are within both S&P's and Moody's guideline ranges. Table 8 (below) indicates that an FFO Interest Coverage ratio for Yukon Electrical in the range of 4.2X to 4.7X would be higher than the achieved ratios of other Canadian transmission and distribution utilities (3.8X), which would be reasonable given Yukon Electrical's higher business risk. However, at a 52.5% equity ratio, the ratio would be similar to, but still lower than, the average FFO coverage ratios achieved by the low risk (A rated) U.S. electric utilities (4.9X).

As shown in Table 8, an FFO/Total Debt ratio for Yukon Electrical of 22% to 25% would be higher than the average achieved FFO/Total Debt ratios of other Canadian electric utilities (17.5%), but, at a 47.5% equity ratio, similar to the average of the low risk (A rated) U.S. electric utilities (22.3%).

Table 8

Electric Utilities with Rated Debt	**Ratings DBRS/Moody's/S&P**	**FFO Interest Coverage (2004-2006)**	**FFO to Total Debt (2004-2006)**
Canadian Electric Utilities:			
All	A/Baa1/A-	3.5X	17.5%
Transmission & Distribution	A/Baa1/A-	3.8X	17.5%
Integrated	A(low)/Baa2/BBB+	3.3X	14.2%
U.S. A-rated Electric	na/A2/A	4.9X	22.3%

Source: Schedules 2 and 3.

Although S&P no longer publishes a guideline range for pre-tax (or EBIT)[24] interest coverage ratios,[25] it is still considered an important quantitative financial ratio by all three debt rating agencies (S&P, DBRS and Moody's). It has also been a key ratio considered by regulators (e.g., EUB and BCUC) in assessing capital structures. Moreover, in contrast to the FFO coverages, which are driven in part by depreciation expense, EBIT coverage is more a function of capital structure and return on equity.

S&P's most recent EBIT interest coverage guideline range for an A rating at a "4" business profile score was 3.3X to 4.0X.[26] At common equity ratios of 47.5% and 52.5%, the benchmark return on equity of 8.75%, Yukon Electrical's embedded debt cost of 6.83%, and an income tax rate of 34%,[27] Yukon Electrical's EBIT interest coverage would be in the range of approximately 2.8 to 3.2X. Table 9 below demonstrates the calculation of the EBIT interest coverage at a 50% common equity ratio.

Table 9

	Cost Rate	**Percentage**	**Weighted Component**
	(1)	(2)	(3)=(1) x (2)
Debt	6.83%	50.00%	3.42%
Common Equity	8.75%	50.00%	4.375%
Tax Rate (t)	34%		
Income Tax = 4.38 x (t/(1-t))			2.25%
Pre-Tax Return			10.04%
EBIT Interest Coverage[1/]			2.94X

[1/] EBIT Interest Coverage = Pre-Tax Return ÷ Weighted Debt Component.

The indicated EBIT interest coverage ratios of 2.8X to 3.2X at common equity ratio of 47.5-52.5% are below the bottom end of S&P's guideline range for an A rating.

[24] Earnings before Interest and Taxes.
[25] Moody's has not, to my knowledge, ever published an EBIT interest coverage guideline.
[26] S&P, *Utilities and Perspectives*, June 1999. The EBIT interest coverage guideline ranges were excluded from the quantitative guidelines after June 2004, but the actual EBIT interest coverage ratios continue to be provided in the annual utilities' *CreditStats* published by S&P.
[27] Statutory combined Federal (19%) and Yukon Territory (15%) rate as of 2009.

Table 10 below indicates that an EBIT interest coverage ratio in the range of 2.8X to 3.2X would be somewhat higher than the average for the other Canadian electric utilities. Over the period 2004-2006, the average EBIT coverage ratios for all major Canadian electric utilities and transmission and distribution utilities with rated debt were 2.7X and 2.5X respectively. In light of Yukon Electrical's higher than average business risk, an EBIT interest coverage ratio higher than the Canadian electric utility industry average should be expected. A ratio of 3.2X, however, would still be lower than the 3.6X average EBIT interest coverage ratio achieved by low risk (A rated) U.S. electric utilities, which, is partly attributable to the low risk U.S. utilities' higher achieved returns on equity (11.8%, see Schedule 2) relative to the 8.75% benchmark return on equity.

Table 10

Electric Utilities with Rated Debt	**Ratings DBRS/Moody's/S&P**	**EBIT Interest Coverage (2004-2006)**
Canadian Electric Utilities:		
All	A/Baa1/A-	2.7X
Transmission & Distribution	A/Baa1/A-	2.5X
Integrated	A(low)/Baa2/BBB+	2.6X
U.S. A-rated Electric	na/A2/A	3.6X

Source: Schedules 2 and 3.

In summary, my estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of the 47.5% to 52.5% range (i.e. at 52.5%).

VIII. DEBT RATING AGENCY COMMENTARY

As indicated in Sections VI and VII above, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a utility. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity base on which it is allowed to earn, but also the allowed return on equity and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S. The investment community has also indicated to the National Energy Board that it believes the financial parameters adopted for regulated companies are too low.[28]

DBRS

DBRS has commented generally on the relatively low common equity ratios and returns that are being allowed in Canada. In a May 2003 commentary, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, DBRS noted that it would like to see both the deemed common equity ratios increased as well as increases in allowed returns to levels more consistent with U.S. returns.

In December 2004, subsequent to the EUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity ratios and equity returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (return on equity) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

[28] National Energy Board, *Canadian Hydrocarbon Transportation System*, August 2005, June 2006 and July 2007.

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[29] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.[30]

Standard and Poor's

With respect to S&P, in early March 2003, the debt rating agency announced that it was reevaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation).

S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

Like DBRS, S&P has made references to the low deemed equity ratios and equity returns allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. For example, S&P commented on the thin equity layers (and the low returns) allowed the ATCO group of utilities after the EUB decision, stating,

[29] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The return on equity of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower return on equity is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

[30] Other DBRS reports have referenced the low approved returns on equity as a "challenge" for Canadian utilities, i.e., ATCO Ltd. (January 2007), CU Inc. (January 2007), Union Gas (March 2007) and FortisAlberta (May 2007).

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004)

In a more recent report for Yukon Electrical's parent, CU Inc. (rated A), S&P stated in reference to the company's businesses in Alberta,

> Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities (S&P, *CU Inc.*, October 26, 2007)

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[31] As indicated above, the "aggressive leverage" is largely a result of regulatory directives.

In sum, the debt rating agencies consider the allowed common equity ratios for Canadian utilities to be relatively thin and the allowed ROEs to be relatively low. (Actual equity ratios will generally track allowed equity ratios, as utilities have no incentive to maintain higher equity ratios than allowed by the regulator for ratemaking purposes.)

Based on the views of the debt rating agencies, in the aggregate, the allowed and actual common equity ratios of other Canadian electric utilities would be on the low side as a point of departure for estimating a reasonable capital structure for Yukon Electrical. In that context, the upper end of a 47.5%-52.5% common equity range would be reasonable for Yukon Electrical and allow the benchmark return on equity to be applied without an incremental equity risk premium.

[31] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

IX. CHOICE OF CAPITAL STRUCTURE AND RISK PREMIUM

As previously discussed, I have estimated the common equity ratio that would fully compensate for Yukon Electrical's business risk, i.e., the upper end of a range of 47.5% to 52.5%. A common equity ratio of 52.5% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained. To reach an actual common equity ratio of 52.5%, there would need to be a material equity infusion would be required to bring the actual equity ratio up to 52.5%.[32]

There is a critical concern, however, with this approach. While the shareholders may be willing to accept the Alberta benchmark return on equity as a point of departure for setting the allowed return on equity for Yukon Electrical, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in Yukon Electrical (as well as shareholders in other Canadian utilities with similar allowed returns) consider the allowed returns for Canadian utilities to be to low to be compatible with the fair return standard begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return. In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities over the period 2005-2008Q1 has been approximately 10.4%, approximately 1.5 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-13.8%.[33]

[32] In principle, the common equity ratio could be simply deemed to be 52.5% irrespective of Yukon Electrical's actual common equity ratio. This is not without precedent. For example, the Ontario Energy Board has deemed common equity ratios of 40% for all of the electricity distributors under its jurisdiction. The actual equity ratios of the distributors at the end of the 2006 ranged from negative to 100%. However, Canadian regulators generally have been reluctant to adopt deemed common equity ratios that are materially higher than the actual equity ratios that are maintained by the utilities.

[33] The Conference Board of Canada, in reference to allowed returns for U.S. electricity transmission, underscored the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled Electricity Restructuring: Opening Power Markets, the Conference Board stated,

This consideration leads me to recommend that Yukon Electrical move to an equity ratio of 47.5%, with the difference between a 47.5% equity ratio and the 52.5% ratio that would fully compensate for Yukon Electrical's business risks reflected in an incremental equity risk premium. The estimate of the risk premium recognizes that within the five percentage point range of equity ratios (from 47.5% to 52.5%), the overall cost of capital would be relatively constant. In other words, as the equity ratio moves from 52.5% to 47.5%, the overall cost of capital would not change; the decrease in the equity ratio would be offset by an increase in the common equity return. As demonstrated in Table 11 below, a decrease in the common equity ratio from 52.5% to 47.5% increases the equity return from the 8.75% benchmark return on equity to approximately 9.25%.[34]

Table 11

	Proportion	Cost	Weighted Component
Debt	47.50%	6.15%	2.92%
Equity	52.50%	8.75%	4.59%
			7.52%
		Tax Allowance at 34%	2.37%
		Pre-Tax Cost of Capital	9.88%
Move Equity Proportion to 47.5%			
Pre-Tax Cost of Capital Remains Unchanged at:			9.88%
Less: Weighted Interest Component (6.15% x 52.5%)			3.23%
Pre-Tax Weighted Equity Component			6.65%
Less: Tax at 34%			2.26%
After-Tax Weighted Equity Component			4.39%
ROE at 47.5% Equity (After-Tax Weighted Equity Component / 47.5%)			**9.24%**

> 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. 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.

The same conclusions are relevant to distribution and generation.

[34] Based on a cost of debt equal to the 4.55% forecast 30-year Long Canada yield plus the November 30, 2007 indicated spread for a new 30-year CU Inc. debt issue of 130 basis points, and the 2009 statutory corporate income tax rate of 34%.

The indicated required increase in the common equity return due to the lower equity ratio, and thus the required incremental equity risk premium for Yukon Electrical at a 47.5% ratio, is approximately 0.50%. A 0.50% incremental equity risk premium results in a recommended ROE for Yukon Electrical of 9.25%.

X. CONCLUSIONS

- I have relied on the approach adopted by the EUB and NEB with respect to capital structure, that is, I have estimated the capital structure that fully reflects the business risk of Yukon Electrical.

- The return on equity that would be applied to the capital structure that fully compensates for Yukon Electrical's business risk is the EUB's benchmark return on equity established in Decision 2004-052, as adjusted for changes in the forecast long-term Canada bond yield.

- I recommend that the YUB adopt a single benchmark return on equity for both test years, 2008-2009, of 8.75%, based on the average forecast of long-term Canada bond yields over the period of 4.5%.

- The capital structure for Yukon Electrical should:
    - Respect the stand-alone principle;
    - Be compatible with Yukon Electrical's business risks; and,
    - Maintain Yukon Electrical's creditworthiness and financial integrity.

- Yukon Electrical's business risks are higher than those of the typical Canadian electricity distribution utility and higher than average within the spectrum of Canadian utilities.

- The actual and allowed capital structures of Yukon Electrical's peers, both Canadian and U.S., indicate that, in isolation, the common equity ratio that would equate Yukon Electrical to a benchmark utility would be no less than 50%; taking explicit account of U.S. utilities' considerably higher ROEs relative to the benchmark ROE of 8.75% supports an equity ratio in excess of 47.5%.

- Debt rating agency guidelines for the debt ratio compatible with Yukon Electrical's level of business risk support a common equity ratio in the range of 45-55%.

- Estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of a 47.5% to 52.5% range (i.e. at 52.5%).

- The concerns expressed by the debt rating agencies, as well as other capital market participants, that the common equity ratios of Canadian utilities are too thin (and the ROEs are too low) further support the focus on the upper end of common equity ratio range for Yukon Electrical of 47.5% to 52.5%.

- In sum, the upper end of a 47.5-52.5% common equity range would be reasonable for Yukon Electrical and would allow a benchmark return on equity to be applied without an incremental equity risk premium.

- One critical factor militates against increasing the actual common equity ratio of Yukon Electrical to 52.5%: To require shareholders to commit additional equity capital to have the opportunity to earn an equity return perceived as too low is fundamentally incongruous.

- To address this factors, I recommend increasing the actual common equity ratio of Yukon Electrical to 47.5% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a 47.5% common equity ratio, the allowed ROE for Yukon Electrical should be set at 9.25% for the 2008 and 2009 test years.

APPENDIX A
QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN & CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000

Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001

Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company/Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

Current Ratings and New Issue Indicated Spreads
Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities

	Current Ratings April 1, 2007							2006					2007		2007-2008Q1
	DBRS	**S&P**	**4-10-06**	**6-12-06**	**9-5-06**	**11-6-06**	**1-2-07**	**Average**	**4-2-07**	**7-3-07**	**10-9-07**	**11-26-07**	**Average**	**4-1-08**	**Average**
A Rated															
CU Inc.	A(high)	A	90	94	97	93	92	**93**	90	95	115	130	**108**	157	**117**
Enbridge Gas	A	A-	100	105	100	96	95	**99**	98	110	115	130	**113**	170	**125**
Enbridge Pipelines	A(high)	A-	100	105	100	96	95	**99**	98	105	115	130	**112**	170	**124**
Gaz Metro	A	A	89	94	99	95	97	**95**	94	92	115	135	**109**	172	**122**
Terasen Gas [1/]	A	A	na	na	na	na	na	**na**	na	122	135	145	**134**	168	**143**
TransCanada PipeLines	A	A-	117	120	120	116	115	**118**	115	130	140	160	**136**	215	**152**
Average	**A**	**A-**	**99**	**104**	**103**	**99**	**99**	**101**	**99**	**109**	**123**	**138**	**117**	**175**	**130**
Median	**A**	**A-**	**100**	**105**	**100**	**96**	**95**	**99**	**98**	**108**	**115**	**133**	**113**	**170**	**124**
Split Rated A/BBB															
EPCOR Utilities	A(low)	BBB+	129	132	133	130	135	**132**	130	136	170	185	**155**	255	**175**
Nova Scotia Power	A(low)	BBB	135	140	142	140	138	**139**	132	136	145	170	**146**	205	**158**
Terasen Gas [1/]	A	A	129	145	142	130	130	**135**	119	na	na	na	**119**	na	**119**
Union Gas	A	BBB+	118	123	120	114	107	**116**	109	109	120	150	**122**	185	**135**
Westcoast Energy	A(low)	BBB+	123	128	125	120	118	**123**	119	119	125	155	**130**	185	**141**
Average	**A(low)**	**BBB+**	**127**	**134**	**132**	**127**	**126**	**129**	**122**	**125**	**140**	**165**	**138**	**208**	**145**
Median	**A(low)**	**BBB+**	**129**	**132**	**133**	**130**	**130**	**131**	**119**	**128**	**135**	**163**	**136**	**195**	**141**
BBB Rated															
TransAlta	BBB	BBB	162	168	168	162	170	**166**	170	205	300	325	**250**	390	**278**

[1/] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.8	11.4	3.1
CU Inc.	2.7	18.7	3.6
Enersource	2.1	16.7	3.8
ENMAX Corp.	6.4	46.3	8.1
EPCOR Utilities Inc.	3.0	23.4	4.2
FortisAlberta Inc.[2/]	2.3	17.5	3.0
FortisBC Inc.[2/]	2.2	10.9	2.8
Hamilton Utilities	3.4	32.0	4.7
Hydro One Inc.	3.2	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	26.1	5.7
Maritime Electric	2.5	12.9	2.6
Newfoundland Power [2/]	2.4	14.0	2.9
Nova Scotia Power	2.4	14.2	3.3
Toronto Hydro	2.7	17.5	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	12.5	3.0
Gaz Metropolitain	2.5	24.0	4.6
Pacific Northern Gas [4/]	2.4	26.4	3.2
Terasen Gas	2.0	9.7	2.4
Union Gas [3/]	2.1	12.8	2.8
Pipelines			
Enbridge Pipelines [3/]	3.3	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	15.7	2.8
Westcoast Energy Inc.	2.1	16.4	3.1
Medians			
Electric T&D	**2.7**	**17.5**	**3.8**
Electric Integrated	**2.5**	**14.2**	**3.3**
All Electric	**2.6**	**17.5**	**3.5**
Gas Distributors	**2.1**	**12.8**	**3.0**
All Companies	**2.4**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P						Average ROE 2004-2006
			Average 2004-2006				
Name	**Debt Rating**	**Business Profile**	**Debt Ratio**	**EBIT Coverage**	**FFO/Debt**	**FFO Coverage**	
Alabama Power Co.	A	4	54.3	4.3	22.8	5.6	13.5
Central Hudson Gas & Electric Corp.	A	3	66.3	4.7	16.7	4.3	12.2
Consolidated Edison Co. of New York Inc.	A	2	54.8	2.8	18.7	3.9	10.0
Consolidated Edison Inc.	A	2	57.2	2.6	16.7	3.7	9.2
Duke Energy Carolinas LLC	A-	4	48.0	4.0	28.8	14.9	NA
Duke Energy Corp.	A-	5	48.7	3.2	19.8	3.9	9.9
Duke Energy Indiana Inc.	A-	4	56.7	3.1	17.6	4.6	8.8
Duke Energy Ohio Inc.	A-	5	38.7	4.5	23.2	5.6	11.0
Florida Power & Light Co.	A	4	41.1	5.9	34.1	7.7	11.7
FPL Group Inc.	A	5	51.8	2.7	22.3	4.5	12.4
Georgia Power Co.	A	4	56.0	4.6	22.0	6.1	14.1
Gulf Power Co.	A	4	54.5	3.7	20.9	4.6	12.2
Integrys Energy Group Inc.	A-	5	58.6	3.4	13.8	4.1	12.5
KeySpan Corp.	A-	3	61.8	3.5	16.2	3.9	10.4
Madison Gas & Electric Co.	AA-	4	52.4	4.5	20.4	5.1	10.6
MidAmerican Energy Co.	A-	5	52.4	4.4	26.0	5.8	14.2
MidAmerican Energy Holdings Co.	A-	4	74.9	1.9	11.1	2.5	13.2
Mississippi Power Co.	A	4	63.0	4.2	22.8	10.8	13.9
NSTAR	A+	1	65.4	3.5	22.6	4.9	13.3
NSTAR Electric Co.	A+	1	49.7	5.7	39.4	8.1	13.8
Orange and Rockland Utilities Inc.	A	2	70.8	3.6	16.9	3.9	NA
PacifiCorp	A-	5	59.0	2.5	15.0	3.7	7.0
PPL Electric Utilities Corp.	A-	3	51.0	3.1	26.2	4.9	NA
San Diego Gas & Electric Co.	A	5	54.8	5.0	25.9	6.7	16.3
SCANA Corp.	A-	4	57.6	2.5	22.5	4.2	11.4
South Carolina Electric & Gas Co.	A-	4	50.1	2.6	25.6	5.1	10.3
Southern Co.	A	4	57.0	3.8	22.3	5.3	14.9
Vectren Corp.	A-	4	60.4	2.7	15.9	3.9	10.5
Wisconsin Electric Power Co.	A-	4	52.5	4.8	25.0	6.8	11.8
Wisconsin Power & Light Co.	A-	4	48.1	3.6	31.1	5.9	9.9
Wisconsin Public Service Corp.	A	4	52.3	4.0	22.3	5.4	10.1
Mean	**A**	**4**	**55.5**	**3.7**	**22.1**	**5.5**	**11.8**
Median	**A**	**4**	**54.8**	**3.6**	**22.3**	**4.9**	**11.8**

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest*, November 1, 2007; *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest*, November 9, 2007; and *Credit Stats*, September 2007.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures (DBRS) Issuer (S&P)	A		A-	
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
TransCanada PipeLines	Senior Secured	A		A	Very conservative
	Senior Unsecured	A	A2	A-	
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Electric T&D		**A**	**Baa1**	**A-**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**BBB+**	**Very conservative**
All Electric		**A**	**Baa1**	**A-**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
All Companies		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd. [4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electric Utilities								
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55
ATCO Electric		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55
EPCOR		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55
FortisBC Inc.	3/06; 11/07	BCUC	G-14-06; L-93-07	60.00	0.00	40.00	9.02	4.55
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	1/08	IRAC	UE20937	57.31	0.00	42.69	10.00	na
Newfoundland Power	12/07	NLPub	PU32 (2007)	54.01	1.15	44.84	8.95	4.60 [1]
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na [2]
Northwest Territories Power Corp.	8/07	PUB of NWT	Decision 13-2007	52.26	0.00	48.59 [3]	9.25	4.60
Ontario Electricity Distributors	12/06	OEB	Report of the Board	60.00	0.00	40.00	8.57	4.46 [4]
Yukon Energy	10/05	YUB	OIC 1998/32; Order 2005-12, BCUC G-55-07	60.00	0.00	40.00	9.15	4.55 [5]
Gas Distributors								
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55
Enbridge Gas Distribution Inc	1/04; 1/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23
Gaz Metropolitain	10/07	Régie	D-2007-116	54.00	7.50	38.50	9.05	4.78
Pacific Northern Gas	11/07; 5/07	BCUC	L-93-07; G-55-07	56.20	3.80	40.00	9.27	4.55
Terasen Gas	3/06; 11/07	BCUC	G-14-06; L-93-07	65.00	0.00	35.00	8.62	4.55
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23
Gas Pipelines								
Alberta Natural Gas	11/07; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.72	4.55
Foothills Pipe Lines (Yukon) Ltd.	11/07; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.72	4.55
TransCanada PipeLines	11/07; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.72	4.55
Trans Quebec & Maritimes Pipeline	11/07	NEB	RH-2-94	70.00	0.00	30.00	8.72	4.55
Westcoast Energy	11/07; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.72	4.55

[1] The settlement agreement specifying ROE and capital structure was approved by the PUB.

[2] A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35% if approved.

[3] The capital structure of NTPC includes no cost capital (-.85%).

[4] The 8.57% ROE is for rates to be in effect as of May 2008. As per the 12/06 Report of the Board, the ROE is to be based on the January 2008 *Consensus Forecasts* and the January 2008 spread.

[5] The YUB set YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Utilities																			
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[1/]	[1/]	[1/]	[1/]	[1/]	[1/]	9.40	9.60	9.50	8.93	8.51	8.75
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	na
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[1/]	[2/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**
Gas Distributors																			
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	9.62	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**9.08**	**8.59**	**8.77**
Gas Pipelines (NEB)																			
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.07**	**8.66**	**8.78**

[1/] Negotiated settlement, details not available.
[2/] Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

**COMPARISON BETWEEN ALLOWED RETURNS ON EQUITY
FOR CANADIAN AND U.S. UTILITIES**

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.61	4.08
1991	13.56	9.72	3.84	12.51	8.14	4.37
1992	12.94	8.68	4.26	12.06	7.67	4.39
1993	12.16	7.86	4.30	11.37	6.59	4.78
1994	11.50	8.69	2.81	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.84	6.66	4.18	11.34	6.58	4.76
1998	10.15	5.59	4.56	11.59	5.54	6.05
1999	9.50	5.72	3.78	10.74	5.91	4.83
2000	9.79	5.71	4.08	11.41	5.88	5.53
2001	9.68	5.77	3.91	11.04	5.50	5.54
2002	9.62	5.67	3.95	11.10	5.41	5.69
2003	9.71	5.31	4.40	10.98	5.03	5.95
2004	9.59	5.11	4.48	10.73	5.08	5.65
2005	9.51	4.38	5.13	10.50	4.52	5.98
2006	9.07	4.33	4.74	10.39	4.93	5.46
2007	8.66	4.30	4.36	10.30	4.80	5.50
2008q1	8.78	4.10	4.68	10.37	4.35	6.02
Means:						
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.75**	**4.41**
1994-1998	**11.20**	**7.42**	**3.78**	**11.41**	**6.62**	**4.80**
1999-2007	**9.46**	**5.14**	**4.31**	**10.80**	**5.23**	**5.57**

[1/] 2008 ROE represents results for the full year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; www.federalreserve.gov; www.ustreas.gov.

IN THE MATTER OF the *Public Utilities Act*
Revised Statutes of Yukon, 2002, c. 186, as amended

and

An Application by Yukon Electrical Company Limited
For Approval of Revenue Requirements for 2008 and 2009

REASONS FOR DECISION

APPENDIX A TO BOARD ORDER 2009-2

Table of Contents

1 INTRODUCTION

On April 30, 2008, Yukon Electrical Company Limited (YECL) filed with the Yukon Utilities Board (Board) an Application, pursuant to the *Public Utilities Act* (Act) and Order-in-Council 1995/90*,* for approval of its forecast revenue requirements for the 2008 and 2009 test years and approval of certain deferral accounts (Application).

YECL is a wholly owned subsidiary of ATCO Electric Ltd., a private, investor-owned utility which is a member of the ATCO group of companies. YECL distributes electricity to approximately 15,000 customers throughout the Yukon. The YECL distribution system is fed by power purchased from Yukon Energy Corporation (YEC). In addition, it maintains back-up generating plants in certain communities in the event of a power interruption. YECL also generates and distributes electricity in several remote communities through diesel generating plants.

YECL is seeking approval for the following:

1) A revenue requirement of $46,660,000 for 2008;
2) A revenue requirement of $47,902,000 for 2009;
3) To continue the existing deferral accounts for Purchase Power Flow Through Costs, Fuel Price Flow Through Costs and Costs for the Diesel Contingency Fund; and
4) New deferral accounts to cover the Increased Fuel Costs Associated with Pelly Crossing and an Income Tax Rate Variance Deferral Account.

The revenue requirement for 2008 represents an increase of $2,220,000 over the amount that would be recovered under existing rates and riders; for 2009, the revenue requirement represents an increase of $4,130,000. These amounts represent an increase of 5.9% in 2008 and 5.1% in 2009, but do not include fuel price increases as stated in Section 4 of the Application.

Further, YECL requested that certain affiliate costs associated with ATCO I-Tek Ltd. and ATCO I-Tek Business Services Ltd. — affiliates of ATCO Electric Ltd. — be reserved as placeholders until such time as the Alberta Utilities Commission (AUC) rules on those costs as part of the benchmarking process before the AUC.
The Applicant also sought an Interim Rate Rider (Rider R), and Temporary Refund/Surcharge Rider (Rider G). These riders were to apply to all rate classes for YECL and YEC retail customers, except for Secondary Energy Rate 32 and Industrial Primary Rate 39.

In Board Order 2008-4, dated May 16, 2008, the Board ordered YECL to publish a Notice of Application and pre-hearing conference no later than May 23, 2008, in such appropriate local news publications in YECL's service area. YECL was also ordered to make the application and supporting materials available for inspection at its Whitehorse office at 100-1100 First Avenue and at the Watson Lake and Haines Junction public libraries.

On May 20, 2008, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to Section 50 of the Act.

The Board held a pre-hearing conference on June 12, 2008, in Whitehorse, at which time the Board heard submissions from parties on the following matters:

a) Issues List
b) Intervenor and Observer Status
c) Hearing Cost Process
d) Proceeding Schedule
e) Hearing Process
f) Interim Application

On June 20, 2008, the Board issued Order 2008-5, in which Intervenor status was granted to:

- Yukon Energy Corporation (YEC)
- City of Whitehorse (CW)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Department of Energy, Mines and Resources, Government of Yukon
- John Maissan, Leading Edge Projects Inc. (LE)

Observer status was granted to Paul Kishchuk, Vector Research. This Order also established a Proceeding Schedule for the Application and the Issues List. In addition, the Board directed YECL to file additional information as described in the Order.

Board Order 2008-6 approved an increase of 5.0% to existing primary base rates to be applied effective August 1, 2008, in the form of Interim Refundable Rider R. The Board denied the request for Rider G.

The Proceeding Schedule was further revised with Board Order 2008-7 when YECL requested additional time to provide responses to Information Requests (IRs) given the large volume of IRs. In addition, Board Order 2008-9 ordered YECL to provide further and better IR Responses in accordance with the Reasons attached in Appendix A to the Order by the close of business on September 15, 2008. The Board also allowed an additional round of IRs on depreciation through Board Order 2008-11.

On October 7, 2008, the Board held an oral public hearing in the City of Whitehorse, Yukon, before the Board comprised of Chair Wendy Shanks, Vice-Chair Robert Laking, and members Richard Hancock, Jody Woodland, and Kathleen Avery.

The Board directed the parties to file final argument by October 27, 2008 and reply argument by November 10, 2008. The Board considers the evidentiary portion of this proceeding closed as of November 10, 2008.

In reaching the determinations contained within this Decision, the Board has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 DISCUSSION OF ISSUES

2.1 Sales and Revenue

YECL forecast total primary sales to increase 0.8% in each of 2008 and 2009 while wholesale sales were forecast to remain at their current level of 488 MWh. Secondary sales were forecast to decrease by 28.5% in 2008 and a further 58.7% in 2009. The reduction in secondary sales was primarily due to the reduced availability of surplus hydro as a result of YEC sales to the Minto Mine.

The revenues associated with the energy forecast, including the proposed rate increases, are projected to be $45.8 million and $47.1 million respectively for 2008 and 2009.

FORECAST[1]	**Actual 2007**	**Forecast 2008**	**Forecast 2009**
Primary Sales (MWh) Growth Rate (%)	267,698	269,913 0.8	272,054 0.8
Secondary Sales (MWh) Growth Rate (%)	23,566	16,853 -28.5	6,954 -58.7
Total Company Sales (MWh) Growth Rate (%)	291,752	287,255 -1.5	279,497 -2.7
Total Revenues from Existing Rates[2] ($000) Growth Rate (%)	40,177	39,970 -0.6	39,557 -1.3
Total Revenues from Proposed Rates ($000)		45,850	47,075
Rate Increase from Existing Rates ($000) Less: Impact of higher Fuel Costs (Recovered through Rider F) Net Rate Increase from Existing Rates ($000)		5,881 (3,661) 2,220	7,518 (3,388) 4,130
YECL Primary Retail Revenue YEC Primary Retail Revenue Total YEC/YECL Primary Retail Revenue		33,677 3,795 37,471	33,937 3,750 37,687
% Rate Increase over Existing Rates		5.9	11.0

2.2 Forecast Process

YECL's forecast process involved a review of historic sales data by customer class and took into account the most recent information available at the time the forecast was prepared. YECL obtained the information through its work in the community and consultations with CW, Government of Yukon and local developers. In its Application,

[1] YECL 2008-2009 General Rate Application, Schedule 2.1; growth numbers have been calculated
[2] Includes YEC Revenue Shortfall (Rider J)

YECL indicated that the secondary sales forecast mainly came from YEC as YEC was responsible for determining the forecast availability of surplus hydro.

The sales forecast was prepared by customer class: residential, commercial, street and sentinel lighting, secondary and wholesale (sales to YEC). Intervenors took issue with what was felt were conservative sales and revenue forecasts made by YECL.

LE in argument stated that a great deal of detailed work went into preparing the sales forecast as outlined in the Application. Further, LE pointed out that information on the record indicated — for example, for the years 1996, 1997, and 2003 to 2007 — that YECL had underestimated their sales forecast. Despite this, LE concluded that the forecast should be accepted as filed.

YEC and CW recommended that the Board not approve YECL's sales forecast. Additionally, YEC did not support LE's recommendation to monitor YECL sales revenue forecast for future consideration.

Acknowledging YEC's point that YECL's actual sales had exceeded its internal business plan forecasts for prior years, YECL argued that the level of scrutiny and detail used to formulate YECL's internal business plan forecasts was nowhere near as rigorous or comprehensive as was used to derive the current General Rate Application (GRA) quality forecast. Further, the internal business plan forecasts were not the result of any statistical analysis and any comparisons made to the non-test year actuals by YEC were inappropriate and unfair. In summary, YECL submitted that the forecasts in its Application must be judged based on the evidence provided on the record and not on the attempt by YEC to derive a comparison that simply does not exist.

Views of the Board

The Board acknowledges YECL's submissions in argument that it had conducted extensive due diligence in respect of preparing its GRA quality forecasts as well as providing a large amount of documentation in its filing. Further, the Board understands that YECL's level of scrutiny and detail used to formulate YECL's internal business-plan forecasts is not as detailed as was used to derive the current GRA forecast.

However, the Board is concerned with the lack of evidence on the record regarding past YECL sales forecasts. The Board notes that the sales forecasts in evidence indicate that YECL's actual sales exceeded its GRA forecast by 3.9% and 1.5% for the years 1996 and 1997 respectively.[3] Further, regarding YECL's internal business plan forecasts for the years 2003 to 2007, the Board notes that the actuals exceeded forecasts within the range of 1.4% to 4.1% over the period.[4]

In considering the evidence regarding YECL's sales revenue forecast in the following sections, the Board will take the above into consideration.

[3] YEC-YECL-2(e) REVISED; dated September 15, 2008
[4] Exhibit C1-18

2.3 Residential Customer Sales Forecast

The residential sales forecast has two key inputs: the net customer additions and the average use per customer (UPC). The energy sales forecast is obtained by multiplying the forecast number of customers by the average UPC forecast.

Energy sales to residential customers are expected to rise 1.3% and 1.1% respectively in 2008 and 2009. YECL's customer count grew by 1.8% in 2006 and 2.1% in 2007 and is forecast to continue in this range with increases of 1.9% and 1.1% in 2008 and 2009 respectively.

2.3.1 Residential Customer Additions

In its argument, noting that the average increase in residential customer additions from 2003 to 2007 was 229, CW submitted that there was no detailed evidence to support YECL's substantial reduction to the growth rate of residential customers for 2009. Accordingly, CW submitted that the forecast residential customer growth rate for 2009 should be 1.9% (the same as 2008); thus, the residential customer increase for 2009 rises to 241 from 143 and at the same time the average number of customers rises from 12,836[5] to 12,934.

YECL replied that CW was dismissive of the facts presented by YECL, which materially affect its sales forecast, without providing any reason for dismissing such evidence. For example, with respect to the forecast number of residential customers for 2009, CW rejected YECL's evidence that the lack of developed land in the Whitehorse area will impact its sales forecast. YECL submitted that the Board should accept its uncontroverted evidence in this regard. Further, YECL suggested that there was no basis to arbitrarily increase the number of customer additions as suggested by CW. YECL submitted that its forecast should be approved as it is based on an extensive examination of the factors impacting such growth and specific information related to expected customer additions.

Views of the Board

The Board acknowledges YECL's statements regarding the availability of developed land in the Whitehorse area and the affect it may have on its sales forecasts. However, the Board notes CW's submission that, respecting residential customer additions for the period 2003 to 2007, the average growth rate was 229 customers or 1.9%. The Board further notes that the average increase of residential customers throughout the period was lowest in 2004 when the increase was 191 or 1.7%.

After carefully weighing the evidence respecting the forecast and actual increases in residential customers on the record, the Board accepts YECL's proposal that the number of residential customer additions grow by 1.9% in 2008. However, the Board agrees with CW that YECL's evidence does not support its forecast for 2009 indicating a significant reduction in the growth rate of residential customers. The Board notes that during the period 2003 to 2007, a 1.7% growth rate is the minimum growth rate for increases in residential customers. Therefore, the Board finds, based on previous years'

[5] Application, Schedule 2.1, Line 2

growth in residential customers, that the number of residential customers will increase by 1.7% in 2009. This 1.7% increase takes into account YECL's projections at the time of filing that there may be a shortage of developed lots in 2009.

Accordingly, the Board directs YECL in its refiling to adjust its 2009 forecast with respect to the number of residential customer additions from 1.1% to 1.7%. To be clear, the Board directs YECL in its refiling to increase the number of residential customers to 12,908 from 12,836 currently in the forecast and to reflect this change in related schedules and its revenue requirement in the GRA.

2.3.2 Residential UPC

The average UPC for the test period was determined by taking a three-year average of monthly UPC by community. UPC was normalized for Whitehorse and Watson Lake area communities using a "Normal" temperature, which is defined as a 20-year (1988-2007) average Heating Degree Days for Whitehorse and a 12-year (1996-2007) average for Watson Lake. Intervenors took issue with the process used to determine the average UPC.

CW in its argument submitted that inconsistencies in the regression analyses raised concerns regarding the soundness of the analyses. First, not all of the communities had their UPC normalized and second, of the communities that had their UPC normalized, the Normal temperatures that were used were different. Respecting the R^2 values used in the regression analyses, CW in its argument, as well as in its reply argument, expressed concerns regarding the use of R^2 values, which were less than 0.7 and YECL's inconsistent approach to justifying the levels of R^2 used in the Application. In conclusion, CW proposed a trend-line analysis[6] and submitted that its analysis was simpler and more trustworthy than the YECL analysis.

YECL replied that the use of 12-year versus 20-year data in no way materially alters YECL's forecast results and certainly does not diminish the validity or accuracy of the methodology used. YECL submitted that it would be highly inappropriate for the Board to abandon the consistent and previously accepted approach adopted by it in developing a sales forecast in favour of convenient "trends" that are not in fact based on any long-term data, and which only serve to fulfill CW's predetermined objective. YECL has clearly shown that weather affects residential sales.

Views of the Board

The Board acknowledges that YECL performed a great deal of detailed analyses to arrive at its sales revenue forecasts as outlined in the Application. However, the Board is not convinced that a more simplified approach could not achieve reasonable results with far less effort and cost to ratepayers. Therefore, the Board directs YECL at the time of its next GRA to include comparisons of its analyses and the analyses undertaken by other utilities in Canada to arrive at sales revenue forecasts.

[6] City of Whitehorse Argument

The Board has concerns with the range of R^2 values used throughout the analyses and YECL's justification for the wide range of values. Accordingly, the Board directs YECL at the time of its next GRA to include a detailed study as to what other jurisdictions consider a minimum value for R^2 that is acceptable in regression analyses.

Additionally the Board notes YECL's use of one variable in its regression analyses and the wide range of R^2 values in YECL's regression analyses. It is unclear to the Board whether or not the use of one variable in regression analyses is a contributing factor to the wide range of R2 values. Consequently, the Board directs YECL to undertake a study that compares the types of regression analyses — for example, univariate or multivariate — that other utilities may use in order to arrive at their analyses.

Considering the range of R^2 values and the lack of evidence as to what constitutes an acceptable R^2 value, the Board is not convinced that the residential UPCs as calculated are reasonable. The Board is of the view that a 2% increase in YECL's residential UPC is reasonable as it appears to be the low end of the variance where actual residential UPCs exceed forecast YECL residential UPCs. Therefore, the Board directs YECL in its refiling to increase its residential UPC by 2%, and to reflect this increase in all related schedules and its revenue requirement for the test years.

2.3.3 Commercial Sales Forecast

In the Application, the forecast UPC for existing commercial customers, except as noted in the Whitehorse area, was determined by taking a three-year average of monthly UPC by community. YECL based its Whitehorse commercial customer UPC forecast on the 2007 weather-normalized and adjusted UPC. YECL indicated that use of 2007 forecasts captures the impact of the larger commercial customers who came online in 2005, 2006 and 2007. Additionally, the Whitehorse 2007 UPC was adjusted to remove load specifically attributable to the Canada Winter Games.

Increased sales to the commercial class were due primarily to new commercial customers. Customer additions were forecast to increase by 1.1% in both 2008 and 2009. YECL anticipated most of the new commercial customers in its forecast to be running at or below the average UPC, keeping the growth in energy sales to a modest 0.4% and 0.5% in 2008 and 2009 respectively.[7]

In response to CW-YECL-15(d), YECL provided three reasons for the 1.4% reduction in commercial UPC between 2007 and 2009:

- Several new customer additions in 2008 and 2009 with lower than the 2007 annual average would bring down the overall average;
- The three-year average historical UPC used as the 2008 and 2009 UPC forecast for existing customers outside of Whitehorse was lower than the 2007 actual UPC; and
- The Whitehorse UPC based on the 2007 weather-normalized UPC and adjusted for the one-time load attributable to the Canada Winter Games resulted in a reduced Whitehorse normalized commercial average UPC forecast.

[7] Application, page 2-4

Having concerns with YECL's response to CW-YECL-15(d), CW in its argument indicated that without the detail required to support these forecasts, serious doubt was cast on the UPC forecast for 2009.[8] CW further pointed out that the one-time Canada Winter Games adjustment did reduce the Whitehorse normalized commercial average UPC in 2007, but was not significant enough to change the upward trend in commercial UPC in Whitehorse for the period from 2003 to 2007. CW stated that the three-year historical commercial UPCs were lower than their 2007 actual UPCs because the commercial customers outside the city of Whitehorse had UPCs that had trended upward for the years 2005 to 2007. In conclusion, CW submitted that YECL's downward trending commercial UPC forecasts for 2008 and 2009 are unpersuasive as the explanations provided in CW-YECL-14(d) and YEC-YECL-2(j) were general in nature, unconvincing and misleading.

YECL in reply argued that the fact that customer-specific information was not provided on the record does not detract from the validity of the positions presented by YECL in its evidence. Further, YECL submitted that the use of a three-year commercial UPC was common practice, was previously used and approved in the 1996-97 GRA, and should be accepted by the Board.

Views of the Board

The Board is not convinced that there is justification for the proposal by YECL to level off or reduce CW's UPC for the test period. The Board notes that UPCs for the commercial customers outside the city of Whitehorse, for the most part, have been increasing over the period 2005 to 2007. Therefore, the Board is not persuaded that the use of a three-year average justifies a decrease in commercial average UPCs for communities outside of Whitehorse. Further, the Board has concerns with the lack of data that forms the basis of the small load commercial customers connected to the system in 2009. The Board has concerns with the difficulties that YECL experienced in obtaining monthly UPC data[9].

Considering the above, the Board finds that the commercial UPC forecast should be increased. The Board finds an increase of 2%[10] is reasonable for the test years; 2% is in the lower range of values that represents YECL's consistent under forecasting and sales revenues. Accordingly, the Board directs YECL in its refiling to increase its commercial sales forecast by 2%. To be clear, the Board directs YECL in its refiling to increase its 2008 and 2009 MWh sales per customer[11] to 55.7 and 55.3 respectively.

Further, the Board directs YECL in its next GRA to provide a comparative study as to the analyses other utilities make use of to derive sales-revenue forecasts. The study should answer, but is not limited to, the following: What is the predominant methodology for forecasting sales revenues, i.e. averaging techniques, regression analyses, other? If averaging is used, what length of interval to average over is recommended and why? If

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8 Detailed information on the new customers cannot be provided due to customer confidentiality; CW-YECL-15(d)
9 YEC-YECL-2(j).
10 The forecast range can be referenced in YEC-YECL-2(e) Revised, September 15, 2008 and Exhibit C1-18.
11 GRA Application, Schedule 2.1

regression analyses are used, how many variables account for the variability, what value of R^2 is valid, what are other relevant statistics?

3 PURCHASE POWER

Purchase power costs included in the Application were expected to remain relatively flat for the test period:

Description[12]	Actuals ($000)		Test Period ($000)	
	2006	**2007**	**2008**	**2009**
Primary Purchase Power	17,227	17,436	17,790	18,003
Secondary Purchase Power	1,130	1,194	1,028	424
Shortfall Rider J	4,882	5,017	5,028	5,067
Total Purchased Power	23,239	23,647	23,846	23,494

Approximately 90% of the power supply required by YECL is purchased from YEC. The purchases are for YECL's customers on the Whitehorse-Aishihik-Faro (WAF) and Mayo-Dawson (MD) grids. The amounts included in the Shortfall Rider J are related to YEC's Shortfall Rider J and are a flow-through for YECL.

YECL requested approval of two deferral accounts. The first deferral account is related to increases or decreases to the cost of purchased power, which was based on YEC's rates that were in place for primary energy and secondary sales[13]. YECL indicated that subsequent increases or decreases to these rates would be flowed through to YECL's customers. YECL also requested the continuation of the Diesel Contingency Fund (DCF) mechanism as approved in the 1996-97 GRA.

In its Application, YECL stated that Fish Lake hydro generation throughout the test period was based on the average generation over the last 10 years and adjusted for estimated downtime in the test period for required rebuilds. Intervenors took issue with the basis of YECL's Fish Lake hydro generation forecasts as well as the expensing of purchase power costs associated with the Fish Lake hydro rebuilds.

In its argument, YEC indicated that the DCF as established in the 1996-97 GRA settlement (Ex.C1-11, Tab 5) directed that "Rates and the fund will be determined using the long-term average water expected to be available for generation". YEC pointed out that the forecast Fish Lake generation (6.8 GW.h) at Fish Lake throughout the 2008 and 2009 test period was 3.8 GW.h below that which was forecast in the 1996-97 GRA and compared with 2007, the Application forecasts a reduction 2.8 GW.h in each test year.

YEC recommended that the Board direct YECL to adjust its Application so that Fish Lake hydro generation reflects the Fish Lake hydro long-term average water expected to be available for generation. YEC further recommended that the long-term average be

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12 YECL 2008-2009 General Rate Application, page 3-1
13 YECL 2008-2009 GRA Application; Schedule 3.1, lines 6 and 7

based on all years of available data and not, as was done in the Application,[14] based on the last 10 years on record.

Contrary to YEC's argument, LE submitted that YECL should use a Fish Lake generation forecast that reflects recent practice, 6.962 GW.h per year, and that any generation below this actually experienced due to the required rebuilds should be clearly documented.

LE and YEC agreed and submitted in argument that YECL should be required to capitalize the purchase power required because of the Fish Lake Hydro rebuild. This would better reflect all relevant capital costs associated with the hydro rebuild and would avoid artificially raising test-year rates to recover added purchase power related to the Fish Lake Hydro rebuild.

In its reply argument, YECL indicated that relying on a 10-year average, adjusted for the planned rebuilds, was a reasonable approach considering the forecast output was higher than actual output in six of the last 10 years. Accordingly, YECL submitted that the forecast of purchase power, including the amount of generation from Fish Lake, was reasonable and appropriate for the test years and should be approved by the Board, as filed. With respect to the capitalization of purchase power costs associated with the Fish Lake rebuilds, YECL in its reply argument, submitted that it had followed a standard methodology in determining that these costs should be expensed and this approach should be approved by the Board.

Since there was little debate concerning the deferral accounts, YECL in its reply submitted that these deferral accounts should also be approved as requested.

Views of the Board

The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized.[15] Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time.

Further, the Board notes LE's argument that indicated that incremental power purchases incurred because of the required rebuilds should be clearly documented. The Board agrees that this is a reasonable approach. Therefore, the Board directs YECL in its refiling to capitalize the forecast purchased power costs associated with the Fish Lake rebuild and to not treat these costs as an expense item in the test years. The Board further directs YECL at the time of its next GRA to provide clear documentation of these incremental power purchases from WAF due to the Fish Lake hydro rebuild.

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[14] The record that shows the basis for calculating the 10.042 GWh/yr average adopted in the 1996/97 GRA as well as the adjusted average when including the additional years of record now available; YEC Argument, page 13

[15] Transcript; pages 275 - 276

The Board acknowledges that there was little debate regarding the deferral accounts described in the Application, i.e. the Diesel Contingency Fund and Rate from YEC[16]. Therefore, the Board approves YECL's request for continuation of the aforementioned deferral accounts (see Footnote 16).

The Board is concerned with the YECL's proposed Fish Lake hydro generation forecast of 6.2 GW.h for each of the test years, which is a 3.8-GW.h reduction from the 10 GW.h of generation proposed in YECL's last GRA. The Board notes that YECL's statement that the 10-year average for Fish Lake generation of 7 GW.h is higher than the actual output in six of the last 10 years[17]. However, the Board notes that the average generation for the years when output exceeded the 7 GW.h, the average generation for the four years was almost 9 GW.h.

In making a determination on this issue, the Board considered YECL's submission in argument that it is in a new water-licence period and is subject to certain restrictions. Further, the Board accepts YEC's suggestion that the available generation at the Fish Lake hydro plant should be based on all years of available data. Accordingly, the Board finds 8.73 GW.h[18] is reasonable as the base generation for the Fish Lake hydro facility, prior to considering the impact of any downtime due to the Fish Lake hydro rebuilds. Therefore, the Board directs YECL in its refilling to reflect base hydro generation of 8.73 GW.h.

4 DIESEL FUEL COSTS

The following table[19] shows total diesel fuel costs included in the Application:

	Actuals ($000)		Test Period ($000)	
	2006	2007	2008	2009
Diesel Fuel Costs	2,026	2,054	5,715	5,299

The forecast diesel fuel cost increase of $3.6 million in 2008 is mainly due to the inclusion of the Rider F fuel rider in base rates for the test period.[20] The forecast diesel fuel cost decrease of approximately $0.4 million in 2009 is due to reduced diesel generation in Pelly Crossing because of its interconnection to the WAF grid. YECL is seeking continuation of Rider F as well as a deferral account for the incremental costs associated with a change to the assumption that Pelly Crossing's connection to the WAF grid would be effective November 1, 2008.[21]

In its argument, LE pointed out that YECL has not proposed conservation or efficiency programs in its diesel communities despite incurring diesel fuel costs greater than $5 million in 2006 and 2007. In light of the high diesel fuel costs, LE and YEC submitted

16 GRA Application; page 3-2
17 YUB-YECL-05 Attachment 1.xls
18
19 YECL 2008-2009 General Rate Application, page 4-1
20 Prior to 2008, YECL recovered the difference between the forecast 1997 fuel rates and the current fuel rate using Rider F.
21 Pelly Crossing deferral account basis shown in the Application, page 4-3

that YECL should be directed to initiate energy conservation and efficiency programs in its isolated communities.[22]

In respect of the proposed Pelly Crossing deferral account, LE and YEC argued that if the Board were to approve the deferral account, any delays in connecting Pelly Crossing to the WAF grid should be clearly documented and justified. Additionally in its argument, YEC submitted that the Board should seek clarification from YECL with respect to how the Pelly Crossing deferral account would provide benefits to ratepayers, should it be connected to the grid earlier than November 1, 2008.

In its reply argument, YECL stated that it was always amenable to participating in conservation programs albeit YECL's experience has been that such energy conservation and efficiency programs have typically been led by a government-based entity. With respect to the Pelly Crossing deferral account, YECL indicated that the requested deferral account clearly meets the standard criteria for the approval of such a mechanism and accordingly submitted that the deferral account should be approved, as requested.

Views of the Board

With respect to the proposed Pelly Crossing deferral account, the Board notes that the typical criteria used in determining whether to approve the use of a deferral account are the level of uncertainty regarding the accuracy of the forecast and the utility's ability to control the factors influencing the forecast. The Board agrees with YECL that the Pelly Crossing deferral account meets the standard criteria and is reasonable and appropriate.

The Board agrees that YECL's proposal to continue a diesel fuel price rider deferral account, in order to address differences between forecast and actual fuel prices, is reasonable and appropriate. Therefore, the Board approves YECL's proposal for a diesel fuel price rider.

5 OPERATIONS AND MAINTENANCE EXPENSES

For 2008 and 2009, YECL has requested approval of operations and maintenance expenses (O&M) totaling $8.8 million and $9.3 million respectively. The Board notes the actual O&M for 2006 was $7.0 million while actual O&M for 2007 was $7.3 million

5.1 Labour Costs

In regard to labour costs, YECL indicated that it had to respond to competitive market forces (i.e. the tight "south of 60" labour market, and the reluctance of people to move to the north when high-paying jobs are available in the south) by developing and offering a compensation package that provided a fair compensation.

Expectations were that an average job-class wage increase of 9.5% for 2009 would result from the fall 2008 negotiations.[23] For the test period, this agreement also provided

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[22] LE Argument, Page 9.
[23] The 2009-2010 collective agreement

wage increases related to certain job classifications that were technical in nature and mandatory to delivering safe and reliable service to customers. Additionally, commencing in 2009, YECL indicated that employees would also be entitled to additional travel benefits.

In argument, YECL stated that it had introduced programs that would assist it in attracting and retaining necessary resources, and its ability to provide safe and reliable service would be compromised if the cost pressures were not recognized and the associated O&M costs approved in its revenue requirement.

LE argued that YECL's staff remuneration proposals should be accepted but because of the significant increases, the approved FTE complement should be reduced. In its argument, YEC indicated that O&M labour cost increases from 2007 to 2009 equaled 36.7%, as compared with average annual increases of about 4.45% from 2003 to 2007. Further, YEC indicated that no requirement to pay the 9.5% existed in the collective agreement with YECL's employee association and the 9.5% figure was largely based on assumptions derived from remaining competitive with an Alberta-based market as opposed to a Yukon-based market.

YEC submitted that the Application had not provided sufficient evidence to support the 9.5% increase and recommended that the Board not approve a revenue requirement wherein the labour costs had yet to be negotiated.

In reply argument, YECL stated that it considered the information provided throughout the proceeding to be an accurate indication of what it would be required to pay under its own collective bargaining agreement for 2009. Further, YECL relied on the Sierra Systems to assist it in developing appropriate compensation measures that would assist it in remaining competitive in the marketplace.

In reply argument, YEC submitted that emerging market conditions suggested that caution should be taken in assuming that the tight labour market in western Canada would continue. YEC also submitted that a reasonable cap on overall O&M cost increases would avoid the need to interfere in the details of remuneration negotiations.

Views of the Board

The Board acknowledges the pressures that YECL has operated under with respect to maintaining its workforce complement, due to the tight labour markets in Western Canada in the past and the reluctance of people to move north. Although, as YECL stated in argument, no Intervenor took issue regarding the challenges that the utility faced with respect to securing and retaining qualified personnel over the past number of years, the Board must determine whether YECL has shown its forecast is reasonable.

The Board notes that YECL submitted the Application prior to entering into negotiations with its employee association. Further, the Board notes YECL employed the services of a third party to assist it in developing appropriate compensation measures that would help YECL retain its competitive position in the marketplace.

That being said, the Board has concerns respecting YECL's proposal for an average job-class wage increase of 9.5% for 2009 that YECL expects to result from the fall 2008 negotiations, considering the 22.5% increase in average compensation per FTE from 2007 to 2009. The Board notes that for the period from 2003 to 2007 the compensation increase was almost 18%, or 4.45% on average.[24] However, the 9.5% increase had not been negotiated at the time of the hearing. The Board is of the view that the tight labour market in western Canada is unlikely to continue seeing the emerging market conditions at the time of the hearing. As the Board considers the best available information at the time of the hearing, the Board is of the view that YECL has not shown that 9.5% increase in 2009 is reasonable. Rather the Board is of the view that the proposed increases for the test period are excessive. Further, the Board finds it reasonable to approve average annual compensation increases for the test period of 6.0%. Therefore, the Board directs YECL in its refiling to reflect a compensation increase per FTE of 6.0% for each of the years in the test period.

5.2 Vacancy Rate

YECL proposed a vacancy rate of 4.0% (2.25 FTEs) to be applied to all labour expenses for 2008 and 1.7% (2.0 FTEs) for 2009.

In argument, YEC stated that, given the fact that YECL had not been before the Board for a review in more than 10 years, the historic FTEs and vacancies that have occurred over that period are essential to understanding, on a go-forward basis, the relationship between FTEs and safe and reliable operation of a utility.[25] YEC further argued that no evidence is available that would provide assurance that the programs proposed by YECL to reduce vacancies would be successful or that the vacancy rates would be materially different than those experienced over the past decade. Accordingly, YEC recommended that the Board set YECL's O&M costs for revenue requirements based on the evidence regarding actual YECL average annual vacancy rates from 2003 to 2007.

In its argument, CW indicated that the average actual vacancies from 2003 to 2007 was 3.5[26]. Referring to YECL's response to CW-YECL-24, CW submitted that the downward pressure on the vacancy rates instituted by the Community Skills Premium would be offset by upward pressure created by employees wanting to work for other prominent companies in the north that offer superior benefits. Accordingly, CW submitted that the Board should rule that the FTE vacancy rate be 3.5 for both 2008 and 2009. YEC agreed with CW's recommendation.[27]

In its argument, LE submitted that YECL's FTE be approved as 55.43 in 2008 and 2009, and that the approved vacancy rate should be 1 FTE. LE further argued that if YECL's Automated Meter Reading (AMR) project was implemented the number of FTEs should be automatically reduced by one.

[24] Exhibit C1-14; YEC Argument, page 21
[25] YEC Argument, page 22
[26] City of Whitehorse Argument, Section 5.0, Vacancy Rates; Undertaking document, page 7 of 212
[27] YEC Reply, page 22

In reply argument, YECL indicated an average vacancy-rate approach, if adopted for the test years, would ignore the extensive programs that YECL had implemented in order to address its resource requirements and the success of these programs. Further, contrary to CW's evidence, YECL's enhanced efforts and increased benefits are working as it has been able to fill the vacancies previously experienced. Therefore, YECL submitted that its forecast vacancy rate was reasonable and appropriate given the current circumstances and should be approved by the Board, as filed.

Views of the Board

Because of the lack of evidence in support of the vacancy forecast, the Board finds that YECL has not met its burden of proof and is not approving YECL's proposed FTE vacancy rate forecast. The Board agrees with YEC that there is no assurance that vacancy rates will be materially different than those experienced over the past decade. Considering the above, the Board finds a vacancy rate of 3.5, the average actual vacancies for the period 2003 to 2007, to be reasonable for the test years. Therefore, the Board directs YECL in its refiling to reflect a vacancy rate of 3.5 FTEs for each of the test years.

5.3 Non-Labour Costs

YECL forecast non-labour costs in two parts: (i) ongoing operational and administrative activities (O&A), and (ii) new programs or projects. For non-labour costs, YECL proposed that an Alberta-based inflation rate of 5.0% be applied for each of the test years. In the Application, YECL explained that ongoing O&A are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.

In its argument, YECL iterated that Alberta rates remain appropriate as this is the location of YECL's parent company, from which it acquires a number of services and materials. Furthermore, YECL stated in response to YEC-YECL-9 that it had experienced inflationary increases at least as high as the Alberta inflation rate. Given that the year-on-year inflation rate to August 2008 was 4%, YECL submitted that its forecast for other inflation was reasonable and appropriate and should be approved as filed.

In argument, LE suggested, in consideration of the global economy, that it did not seem reasonable to source everything from the highest cost province. LE submitted the 5% inflation rate was inappropriate now with the global financial crisis and rapidly declining commodity prices.

Likewise, YEC suggested that a Yukon-based inflation rate would appear to be the most relevant inflation rate for a utility operating within the territory; this would provide for a 2.5% inflation rate. Further, in argument, YEC pointed out that "… YECL selected the highest year-over-year inflation rate since 1988 for any of Canada, Alberta, Whitehorse, and British Columbia ..." [28] YEC recommended that the Board set YECL's O&M costs for revenue requirements based on the 2.5% inflation rate reported for the Yukon.

[28] YEC Argument; page 24

CW submitted in argument that the average increase for non-labour costs for the period 2004 through 2007 was 5.4% while for 2008 and 2009 it was 10.15%, a significant increase. CW further submitted that the 2008 and 2009 inflation rate for non-labour costs should be 3.25% based on a 50/50 weighting of the August 2007 to August 2008 Alberta CPI (4%) and the 2007 Whitehorse CPI (2.5%).

In reply argument, YECL stated that the local rates for Whitehorse, or macro-level rates for Canada, that fall below the 5% rate being utilized by YECL were not appropriate in the current circumstances. YECL indicated that the 5% rate used in the Application was still viewed as a reasonable rate for the two-year test period, given that the year-on-year inflation to August 2008 was 4%. Accordingly, YECL submitted that its forecast for other inflation was reasonable and appropriate and should be approved.

Views of the Board

The Board has concerns with approving YECL's proposed inflation rate of 5%, given that it was an Alberta-based rate and the year-on-year inflation rate to August 2008 was 4%. The Board further notes that the proposed 5% inflation rate represents the highest year-over-year inflation rate, i.e. Canada, Alberta, Whitehorse or British Columbia, since 1998.[29] Accordingly, the Board does not accept YECL's proposed 5% inflation rate for the two-year test period, as YECL has not shown it is a reasonable inflation rate.

Recognizing that YECL purchases a quantum of goods and services outside of the Yukon, the Board does not agree with YEC's recommendation to approve YECL's O&M costs for revenue requirements based solely on a Yukon inflation rate of 2.5%. The Board notes CW's suggestion regarding a hybrid inflation rate comprised of Alberta and Yukon CPI rates.

The Board finds it reasonable that the forecast non-labour inflation rate for 2008 and 2009 be 3.75%, which is calculated using a 50/50 weighting and inflation rates of 5.0% (Alberta) and 2.5% (Whitehorse).[30] The Board therefore directs YECL in its refiling to reflect in its revenue requirement, an inflation rate of 3.75% for its O&M costs other than labour.

The Board shares CW's concerns as to whether or not CPI is the appropriate inflation index to apply to the basket of goods and services purchased by YECL. Accordingly, the Board directs YECL in its next GRA to provide a study that compares what other utilities use as a basis for non-labour inflation rates.

[29] YEC-YECL-9(d)
[30] YUB-YECL-8(f)

5.4 Affiliate Costs

YECL out-sources certain major administrative functions to affiliate companies such as ATCO Electric (AE) to take advantage of the economies associated with the scope and scale of services available from a larger utility. In its Application, YECL indicated the costs of these services to be based on a fully allocated cost methodology that does not contain any element of profit or return.

Further, in addition to labour support provided from AE, YECL purchases information technology and billing system services from ATCO I-Tek and ATCO I-Tek Business Services respectively. YECL explained that these services were being reviewed as part of a benchmarking process and that a final report was to be filed by ATCO with the AUC. YECL stated that it would update the placeholders included in this Application once the appropriate reports had been finalized and approved by the AUC.

During the hearing, YECL indicated that the I-Tek costs were developed from the costs filed before the Alberta Energy and Utilities Commission (EUB) as part of a benchmarking study. When questioned by CW as to why YECL did not regard the rates in the Application as placeholders, to be changed at the time that those rates were fixed in Alberta, YECL's witness stated:

> Again, given the exposure to more proceedings, given that I-Tek – the I-Tek does mirror the I-Tek rates that are in the benchmark report, because it is the same services for I-Tek that Yukon Electrical receives – that ATCO Electric receives. I do appreciate that there is an ongoing process, but to put it in perspective, from an ATCO position, we think the rates are final. Agreed they're not approved, so there could be some adjustments, but we're looking at $300,000 in costs for Yukon Electrical compared to around $50 million of I-Tek costs for the ATCO Utilities. So within that $50 million, that number could change slightly. It's been a four-year process. I don't think it's going to be substantive, but there could be some slight changes. We felt that, rather than let Yukon Electrical get wrapped up in another process, the substantive savings have been captured and are reflected in this filing[31].

In argument, CW indicated that it was prepared to accept YECL's explanation concerning why the Evergreen[32] rates were not employed, i.e. that YECL received different billing services from I-Tek than does AE or ATCO Gas.

Further, notwithstanding this limited acceptance, CW indicated that it was not satisfied that the Alberta CPI rates of inflation used to inflate the benchmarking costs on an annual basis were appropriate. CW opined that information processing costs change at a different rate than the general CPI basket.

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31 Transcript Volume 3, October 9, 2008 page 311 lines 15-26 inclusive.

32 A term used by CW in its Argument under the section for Affiliate Costs (page 20) which refers to a benchmarking process respecting IT and customer-care services that is ongoing before the Alberta Utilities Commission (AUC) in Alberta and involves such ATCO-regulated affiliates as ATCO Electric (AE) and ATCO Gas (AG) and the unregulated company known generically as ATCO I-Tek which provides the IT and customer-care services. The final decision on this AUC process will form the basis of costs from the unregulated entity (I-Tek) to the regulated companies (AE and AG) when the study is completed.

Although it might be more exact to use a placeholder for I-Tek rates, CW considered that it would be more efficient from the regulatory standpoint to accept these rates as final for setting YECL's rates. Finally, CW submitted that the Board should order YECL to file for information purposes the final I-Tek rates that result from the Evergreen process and the difference it would have made for revenue requirement for each test year once the Evergreen process is completed.

Views of the Board

The Board finds CW's proposal to accept these (I-Tek) rates as final for setting information technology and customer care rates appropriate from an efficiency standpoint. Accordingly, the Board approves YECL's proposed affiliate costs subject to the proviso that the inflation rate will be adjusted to the Board-approved inflation rate for non-labour costs (see above Section 5.3). The Board directs YECL in its refiling to align its proposed affiliate costs with the non-labour costs adjusted to reflect the Board-approved non-labour inflation rate.

5.5 Taxes Other Than Income

In its Application, YECL provided actual property tax values for 2006 and 2007 and forecast values for the years 2008 and 2009. Increases in property taxes were said to be primarily due to inflation. "Property taxes are paid … annually for Yukon Electrical's office building, generation facilities, substation properties and power lines."[33] In its Application, YECL requested approval of $249,000 for Taxes Other Than Income for 2008 and $261,000 for 2009.

When questioned by Board counsel, YECL stated that the actual property tax rate for 2008 was 3.8%[34].

YECL was the only party to comment on this in argument where it said that the 7.5% increase for property taxes was the best information at the time and therefore the forecast amount should be approved.

In reply argument, YEC stated:

> … the Board should direct that YECL's application be adjusted to provide for a property tax rate increase in 2008 of 3.8%, with consistent adjustments made as required also to the 2009 property tax forecasts[35].

[33] Application, page 6-1
[34] Transcript volume 3, October 9, 2008 page 389 lines 20-30 inclusive
[35] YEC Reply, page 26

Views of the Board

The Board agrees with the position of YEC that the 3.8% increase for 2008 is the most accurate and up-to-date information in this proceeding. Therefore, the Board directs YECL to use 3.8% as the increase in Taxes Other Than Income for 2008 over 2007 actual costs. The Board accepts the 4% forecast increase amount over 2008 costs for 2009 costs as proposed by YECL.

5.6 Depreciation

5.6.1 Equal Life Group (ELG) versus Average Service Life (ASL) methodologies

Depreciation for 2008 and 2009 for YECL was based on a depreciation study by Gannett Fleming Inc. (the Study). The Study based the depreciation rates on the straight-line whole-life method using the equal-group life procedure.[36] Attachment 1 of Section 7 of the Application contains the Study. Part I explains the scope, Part II describes the Study, and Part III provides the results. Depreciation expense, through the Study was determined to be $4,365,000 for 2008 and $4,837,000 for 2009. The Study is a continuation of the methods and assumptions utilized by YECL in the past. The position of YECL is that the ELG method has regulatory acceptance in several jurisdictions and provides better matching of asset consumption to depreciation expense.

In its argument, YEC stated that for regulatory consistency and to reduce test-year costs for ratepayers, YECL should have considered adopting the ASL approach as well as followed the Future Reserve for Site Restoration directions from Order 2005-12.

YEC contended that the ASL method was widely accepted in Canadian regulatory jurisdictions, was a means to balance utility and ratepayer interests, and was accepted by the Board in Order 2005-12.[37]

YEC further submitted that rate stability is a consideration when determining a depreciation method and that such was a governing factor when choosing the method for YEC in its previous application.

LE was of the view that there was not enough evidence to suggest YECL should change the method of depreciation utilized.

In its argument, YECL stated that the depreciation method employed by YECL was the same method as previously utilized by YECL. YECL confirmed that it supports the expert evidence that Gannett Fleming provided. The YECL position is that the ELG method is technically superior, widely accepted, complies with International Financial Reporting Standards, and should not be changed based on a criteria to reduce the test year revenue requirement.

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[36] Application, Section 7 – Attachment 1, page 2 of 158
[37] From YEC Argument, pages 16-17 inclusive

CW supported the position of YEC (ASL method) in reply argument on the basis of regulatory consistency (the same method utilized by YEC) and the effect of lowering costs and the revenue requirement.

YEC maintained its position that YECL did not propose a depreciation method that is accepted in Canada and would reduce ratepayer costs. Further, it did not make a case that the use of ASL is inappropriate. YEC contended that the question of technical superiority of ELG versus ASL was of no relevance or assistance to the Board[38]. YEC submitted that consistent treatment of a depreciation method (the ASL method) is in the interests of current ratepayers and is not unfair to YECL.

LE said in its reply argument:

> … the short term benefits of the ASL approach would be outweighed by the future higher ratepayer costs when who knows what other cost pressures there might be. The ASL is likely to be short term gain for long term pain. The better intergenerational fairness and the reduction in depreciation expense actually being realized should make it easy to stay the course and continue to use the ELG approach[39].

In its reply argument, YECL said "… that it was YEC, against the recommendation of its expert witness, that sought changes to the depreciation methodology previously approved by the Board, which is indeed consistent with Yukon Electrical's treatment as proposed herein[40]." YECL further asserted that it was adopting the advice of its expert witness on the continuation of the depreciation method employed by YECL. Finally, YECL noted that the use of the ELG method was supported by LE.

5.6.2 Future Reserve for Site Restoration (FRSR)

The issue of FRSR did not appear in the Application. The topic did not come up until IRs were asked of YECL.

In argument, YEC said:

> In Order 2005-12, notwithstanding arguments to the contrary from Yukon Energy and YECL, the Board also directed Yukon Energy to discontinue recording its annual depreciation provision for Future Removal and Site Restoration ("FRSR") costs effective January 1, 2005 (which the Board estimated in its Order at $533,336), ordered a variance for Yukon Energy from Generally Accepted Accounting Principles ("GAAP"), and required that the December 31, 2004 balance in the FRSR account for Yukon Energy remain as a liability to be utilized for dismantling costs that are incurred in 2005 and future years[41].

YEC further stated, "that YECL should be subject to the same treatment regarding FRSR depreciation as directed by the Board with regard to YEC in Order 2005-12[42]."

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38 YEC Reply, page 29
39 LE Reply, page 3
40 YECL Reply, page 18
41 YEC Argument, page 14
42 YEC Argument, page 18

YEC got confirmation through YECL's response to YEC-YECL-II-2 that YECL has a form of FRSR[43] built into its depreciation rates and has a means for separately accounting for that amount. YEC contended that the arguments supporting the continuation of an FRSR item by YECL were parallel to those proposed by YEC in 2005 that were ultimately rejected by the Board. YEC added that the FRSR liability balance to the end of 2007 for YECL was $4,688,111[44] and that the annual costs of FRSR for the test years were $945,000[45] for 2008 and $1,003,000[46] for 2009. YEC asked that for regulatory consistency for both utilities (YEC and YECL) and to show reductions that benefit ratepayers, that YECL should cease recording any provision for FRSR effective January 1, 2008. Forecast depreciation expense, as determined by YEC, would be reduced by $945,000 in 2008 and by $1,003,000 in 2009.

CW submitted that there should be consistency among Yukon utilities for FRSR. CW recommended that the FRSR equivalent be separated to determine total negative net salvage in the reserve and allow the Board and Intervenors to seek if FRSR is reasonable or needs to be capped.

In its argument, YECL stated that based on the testimony of its expert depreciation witness, it is only aware of YEC and B.C. Hydro using an FRSR fund. YECL's position was that the collection of negative net salvage had long been approved by the Board and was a widely accepted practice across North America. Finally, YECL submitted, "that the recovery of net negative salvage through tolls best complies with the depreciation objective to recover the service value of assets over there [sic] estimated lives, and best complies with regulatory fairness[47]."

In reply CW stated:

> While CW considers that it is appropriate to collect certain future costs in the present, over-collecting negative net salvage through rates results in present customers paying the cost of future customers. If the actual cost of site restoration and remediation is less than what was collected in rates, intergenerational inequity will result[48].

Further, CW agreed with YEC in that the accumulated negative net salvage value should be capped as at the end of 2007 and amounts for 2008 and 2009 should be removed from the depreciation rates. It was CW's view that this would bring consistent regulation and result in lower regulatory risk.

Consistency between the two utilities was necessary from the reply of YEC. YEC also noted that it did not choose the method determined by the Board in Order 2005-12. YEC

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43 YECL's form of FRSR is known as negative net salvage
44 YEC-YECL-II-2(c) Attachment 2
45 Ibid
46 Ibid. The above two amounts $945,000 and $1,003,000 were net salvage for 2008 and 2009 respectively. To determine the ending balance for Accumulated Depreciation Net Salvage forecast net salvage amounts need to be removed. These amounts are -$113,000 and -$75,000 for 2008 and 2009 respectively.
47 YECL Argument, page 21
48 CW Reply, page 8

stated that YECL's arguments do not recognize that it was the Board that raised the FRSR issue in 2005 and decided that that was the approach to be taken in Yukon.

In its reply argument, YECL said that YEC is asking the Board to decide this topic based on a previous YEC proceeding and argued that if a decision was made on this basis, it could result in an error of law. YECL maintained that its treatment of negative net salvage was consistent with past practice, based on the expert testimony of its witness, and is widely applied across North America.

Views of the Board

The Board acknowledges that both the ELG and ASL methods are recognized in Canadian regulatory jurisdictions. Until 2005, both YECL and YEC utilized the ELG method when determining the amounts to be included in depreciation. The Board, with the exception noted below, finds that it is in agreement with the findings of the depreciation study undertaken by Gannett Fleming Inc. It is the Board's view that consistency is important and that it is not limited to methods employed across utilities but requires a consistent use of methodology within a utility. In this particular case, both YECL and YEC calculate depreciation and use depreciation expense to determine overall revenue requirement. YECL has demonstrated that it has consistently employed the same methodology. Therefore, the Board accepts the use of the ELG method by YECL.

With respect to FRSR, the Board is persuaded by the arguments of YEC and CW that consistency in this area is important. YECL responded that two critical facts were specific to YEC and those facts were not consistent with the circumstances of YECL: (1) YEC has recorded an Asset Retirement Obligation related to the legal requirement for the removal of facilities in compliance with Section 3110 of the CICA handbook; and (2) The company has recorded FRSR requirements into a separate balance sheet account[49]. The Board is of the view that the substance of the circumstance of YECL is similar to that of YEC. That is, YECL has a salvage obligation and YECL has the ability and can account for amounts equivalent to FRSR. Whereas both YECL and YEC utilized acceptable depreciation methods, the treatment of FRSR or negative net salvage is not consistent between the two utilities. Given that the negative net salvage balance continues to grow, the Board does not believe that there is a need to continue to collect such amounts. YECL is to remove these amounts[50] from its depreciation expense for each of the test years and is not to include any amounts for negative net salvage until Board approval is provided. Further, the Board orders that the December 31, 2007, accumulated amount for net negative salvage be shown as a liability and be reduced as salvage costs are incurred for the years commencing with 2008. Similar to YEC, YECL is to inform the Board and interested parties when the balance for this liability account reaches $2 million.

[49] YEC-YECL-17(g), page 4 of 6
[50] YECL is to remove from depreciation expense $945,000 for 2008 and $1,003,000 for 2009

5.7 Return on Rate Base

5.7.1 Cost of Capital

5.7.1.1 Capital Structure

YECL requested a capital structure consisting of 47.5%[51] equity. The derivation of the capital structure and the rate of return on equity is provided in Attachment 1 of Section 8 of the Application in a report prepared by Kathleen C. McShane (Ms. McShane) of Foster Associates (Foster Report).

The Foster Report described the parameters of the engagement with YECL as follows:

> Yukon Electrical Company Limited ("Yukon Electrical") has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity (ROE) for the Company's 2008 and 2009 test years, using, for the express purpose of these two test years, the benchmark return on equity established by the Alberta Energy and Utilities Board (EUB) as a point of departure[52].

Without restating the Foster Report, the approach used "… is to assess the specific regulated company's business risks then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity"[53]. This was determined through the following three principles outlined in the Foster Report[54]:

1. The Stand Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity

In terms of business risk, the Foster Report said that YECL:

- Is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada;
- Is of higher than average business risk within the spectrum of Canadian utilities; and
- Is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited[55].

Further conclusions in the Foster Report were:

- Capital structures of YECL peers imply that the equity ratio for YECL should be no less than 50%.

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[51] Application, page 8-2
[52] Application, Section 8, Attachment 1, page 1
[53] Application, Section 8, Attachment 1, page 4
[54] For a description of these principles and how they were applied to YECL, see Attachment 1 of Section 8 of the Application, pages 12 to 15 inclusive
[55] Application, Section 8, Attachment 1, page 22

- For YECL's business risk, debt rating agency guidelines suggest a capital structure of 45-55% equity.
- Financial metrics for YECL, with guideline ranges and comparisons for other electric utilities suggest an equity ratio for YECL to be in the upper end of the 47.5% to 52.5% range.
- Debt-rating agencies are commenting the equity ratios and returns for Canadian utilities are too low.

In argument, UCG stated:

> UCG submits that this stand-alone principle falls apart when rationalizing YECL's proposal for raising its equity to debt structure as well as receiving a higher rate of return for being a small stand-alone company. Evidence above shows that YECL does not go out and raise debt on its own, nor do they stand alone when doing business with affiliates and mother corporation.[56].

YEC argued that YECL's application violated several consistency principles. The requested increase in the equity component is, "… a material departure from the common equity ratios approved to date by the Board …[57]" YEC submitted that historically the equity ratio of YECL has been less than that of YEC and that the equity level and ROE as recommended by the Foster Report is higher than that of comparable Canadian utilities. YEC recommended that the equity ratio for YECL not exceed 40%[58].

CW refuted several of the business-risk assessments in the Foster Report. CW pointed out in its argument that the Minto mine was not a YECL customer and the secondary impact of a loss-of-mine load only comes after a lag. Further, CW cited the stability of the public administration sector in Whitehorse and the small amount of generation in YECL's asset portfolio as reasons to support a lower business risk assessment for YECL. In terms of comparing YECL to Northland Utilities (Yellowknife) Limited [NUL(YK)], CW noted that the last approved equity ratio for NUL(YK) was 40% and that YECL is nearly twice the size of that utility[59].

YECL reaffirmed the evidence of the Foster Report in its argument and noted that in Order 2005-12, the Board did not impose a precedent in Yukon when using the BCUC automated-adjustment mechanism. YECL noted that it argued against the BCUC automated-adjustment mechanism approach in YEC's 2005 application. The use of the BCUC, AUC or NEB approaches to determining the rate of return provided results essentially in the same range and YECL utilized this approach, "… as it would avoid an extensive debate over the appropriateness of using the traditional methods to determine return on equity …[60]"

YECL stated that the change in capital structure since their last time before the Board is, "… based on the changes that have occurred in the market and the conditions …[61]"

[56] UCG Argument, page 3, point 18
[57] YEC Argument, page 35
[58] YEC Argument, page 39
[59] CW Argument, page 32
[60] YECL Argument, page 22
[61] Ibid, page 24

YECL further argued that the three principles utilized in the Foster Report are widely accepted and that:

> The fair return standard then requires that the combination of capital structure and ROE produce a return on capital which meets the three requirements of the fair return standard: these three requirements, the comparable returns standard, the financial integrity standard and the capital attraction standard[62] …

YECL reinforced its support for the stand-alone principle, stated that the capital structure and return should be maintained at a level similar to CU's high credit rating. A lower capital structure or return on equity would effectively create a cross-subsidization from CU Inc.

YECL summarized that it was a higher business risk than the typical electricity distribution utility in Canada and that the recommendation for capital structure was based on[63]:

1. Capital structures allowed for YECL peers with any risk premiums adopted;
2. Actual capital structures maintained by other utilities;
3. Guidelines for capital structure and A debt ratings set forth by debt-rating agencies; and
4. Analysis of the resulting financial metrics.

CW replied:

> In fact, Ms. McShane's recommendations result in an interest coverage that is well above the comparable returns of her own sample. Only the recommendation of CW of an ROE of 8.75% and an equity ratio in the 40-42% range results in an interest coverage ratio that is comparable to that of an average Canadian electric utility[64]. YEC also noted that YECL was unable to identify any business risks that exceed those for the average Canadian utility[65].

CW submitted that:

> … YECL has not established in evidence or provided any credible argument as to why its FFO interest coverage ratio should exceed the Canadian average and, therefore, why its equity thickness should lie outside the 40-42% range[66].

YEC replied that it agreed with CW in that YECL is less risky than YEC or NUL (YK). Assuming an ROE of 8.75%, YEC recommended an equity ratio that should be less than the range of 40-43%.

[62] Ibid, page 25
[63] Ibid, page 26
[64] CW Reply, page 10
[65] Ibid, page 12
[66] Ibid, page 13

LE replied that in the past the Board has viewed YECL as a high-grade or low-risk utility[67]. LE recommended an equity ratio of 47.5% on a return of 8.75% or an equity ratio of 42.5% on a return of 9.25%.

YECL replied that the YEC arguments do not consider the evidence in the Foster Report and that the business-risk concerns raised by CW were part of YECL's assessment.

Views of the Board

In response to YUB-YECL-33(c), YECL responded:

> Yes, in principle Yukon Electrical would contribute to the size of CU Inc., and thus provide some small contribution to the size and diversification of the entity which provides its debt.

The Board interprets this response to mean that YECL also contributes (albeit in a small way) to the size, diversification and capital structure on AE. Given that capital in the form of either debt or equity flows to YECL through AE (or through CU), and that there is a strong management influence[68] on YECL through AE, and given the significant affiliated transactions and contracts between YECL, AE and other ATCO companies, this Board rejects the stand-alone principle in determining capital structure.

Responses to YUB-YECL-38(a) whereby YECL stated that YECL does not face a higher regulatory risk than a typical electricity distribution company in Canada and to YUB-YECL-34(e) where YECL stated that the ability to earn the allowed return is not a financial risk but a business regulatory risk give credence to the argument that YECL is not a high-risk utility.

The Board accepts the argument from CW that based on the equity ratio proposed by YECL the FFO[69] interest-coverage ratio is higher than that for other Canadian transmission or distribution utilities. The Board also accepts CW's argument that YECL has not satisfied the Board that YECL's business risks are higher than those of a typical distribution or transmission utility.

Further, in response to YEC-YECL- 40(c), YECL confirmed that YECL has operated at a capital structure of approximately 40-43% equity for the years 2003 to 2007. The Board is not satisfied that evidence has been placed before it which would warrant any upward movement in the equity ratio. Comparable evidence on equity thickness from CW-YECL-36(a) wherein EUB Decision 2004-052, the benchmark capital structure (equity) for electric transmission and distribution utilities is 33 and 37% respectively. CW-YECL-36(c) gives an equity ratio for Ontario distributors of 40%.

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67 LE Reply, page 4
68 Page 5-3 of the application describes the affiliate costs. Page 5-4 describes the affiliated parties, and Schedule 5-3 quantifies the costs. In addition YECL has adopted operational policies such as ROW Maintenance, and is proposing to use AE to implement an AMR system
69 FFO – Funds From Operations

The Board considered the statement[70] in the Foster Report that YECL is of similar business risk to NUL(YK). Oral testimony from YECL confirmed that the actual equity ratio had been approximately 40% and that the last approved (based on a Decision in 2005) equity ratio for NUL(YK) was 40%[71].

The Board is not convinced that the YECL situation or risk profile has changed since its last approved equity ratio for 1997[72] to warrant a substantial increase in the equity ratio.

For these reasons, the Board cannot accept the equity ratio as proposed by YECL. Given current market conditions which are discussed in the Cost of Debt Section, the Board directs YECL to use the last approved[73] equity ratio of 40% which is similar to the more recent (2005) PUBNWT Decision for the equity ratio of NUL(YK).

Finally, in arriving at its finding on this issue, the Board did not consider comments in reply argument by CW and YEC relating to PUBNWT Decisions 24-2008 and 25-2008. The Board considers these comments as new evidence that had not been discussed at the hearing.

5.7.1.2 Cost of Equity

The cost of equity is strongly linked to the capital structure. This was the position of YECL and largely acknowledged by the Intervenors. As noted above, Attachment 1 of Section 8 contains the Foster Report which provides the recommendation for the cost of equity for YECL. YECL accepted the recommendation in the Foster Report, that is, a capital structure of 47.5 % equity and a return on equity (ROE) of 9.25%. Much of the evidence on cost of equity is contained in the Capital Structure section and will not be repeated here.

In argument, UCG submitted that the benchmark rate of return proposed in YECL's application be denied. UCG made a recommendation for an overall rate of return but did not make a recommendation specific to the return on equity.

YEC expressed the following concerns in its argument:

> More specifically, the approach adopted in the Application fails to follow past YUB practice with regard to determining a fair rate of return for YECL (based on Board decisions issued when YECL was previously reviewed by the YUB: 1992-1; 1992-2; 1993-8 and 1996-6), significantly deviates from the AUC benchmarking methodology which it "uses as a point of departure" for determining a fair return, and moves away from the approach utilized by YEC in 2005 to determine its return on equity during the Required Revenues and Related Matters hearing[74].

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[70] Section 8, Attachment 1 - Foster Report, page 22.
[71] Transcript Volume 2, October 8, 2008. Page 169 lines 5 to 27 inclusive
[72] Board Order 1996-6, page 11 of 17, Schedule 4B.
[73] Board order 1996-6.
[74] YEC Argument, page 35

YEC argued that historically the Board has concluded that the business risk of YECL does not differ from that of a high-grade utility. YEC labeled the YECL approach as hybrid as it used a benchmarked rate from one jurisdiction and then made adjustments. YECL is a lower-risk utility when compared to YEC. YEC recommended that YECL use either the AUC benchmarked rate or the BCUC benchmarked rate plus premium (total return on equity would be 9.02%).

LE stated in argument: “A fair return on equity for YECL is probably lower for the proposed capital structure than is being requested”[75].

CW recommended in its argument a return on equity of 8.75%.

YECL stated in its argument:

> The proposal to base the ROE on the AUC formula rather than re-determining the ROE from first principles recognizes that (1) a formula ROE similar to the AUC’s currently governs most of the major Canadian utilities and (2) the validity of the existing formulas is currently undergoing review in two major jurisdictions, before the NEB and the AUC. The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[76].

In reply argument, CW reaffirmed its position that an ROE of 8.75% is appropriate.

YEC noted that although the formula-based approach is being review by the National Energy Board (NEB) and by the AUC, it was last reviewed by the BCUC in 2006 and hence is not under current review. YEC added that YECL stated the NEB, AUC and BCUC formulae within a range yield similar results. YEC recommended an 8.75% ROE with a deemed equity ratio of 40-43%.

LE did not accept YECL arguments that it is a higher risk than other Canadian utilities but did state that the recommendation made in its final argument is appropriate.

YECL disagreed with the position of YEC in its reply argument. YECL did state that it was prepared to accept a return of 9.14% based on the BCUC formula.

Views of the Board

The Board strongly agrees with the part of the YECL argument that states:

> The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[77].

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[75] LE Argument, page 6
[76] YECL Argument, page 23
[77] YECL Argument, page 23

YECL covers a geographically dispersed area with a relatively small customer base. It is incumbent upon the Board to explore ways that yield regulatory efficiency and yet provide fairness to all interested parties. In this regard, the Board supports a formula-based approach to determining ROE issues. YECL used the AUC Generic Cost of Capital as its starting point while YEC supports the BCUC formula[78]. CW was also supportive of the BCUC generic cost of capital[79]. Both YECL and YEC have argued that reference to a formula approach is efficient from a regulatory efficiency perspective. To reference a generic cost-of-capital approach from another jurisdiction, the Board must answer the following questions:

- Which generic cost-of-capital model should be used and from which jurisdiction?
- Should a risk premium be applied?
- If a risk premium is applied, what risk premium level should be applied to YECL?

Which generic cost-of-capital model should be used and from which jurisdiction?

Of the three models discussed (NEB, AUC, and BCUC) the BCUC model has been the most recently reviewed and is not under current review. In reply, YECL said it was prepared to accept a return based on the BCUC formula. Therefore, the Board directs that the BCUC generic cost of capital is the most appropriate as it has been the most recently reviewed, and is generally accepted by the parties.

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation. The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk[80]. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.

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78 Appendix A to Board Order 2005-12, page 43. "Therefore, in their Application, YEC is proposing that the allowed return on equity be set by reference to the BCUC formula approach …"

79 CW Argument, page 28 where CW stated: "For regulatory consistency with YEC, CW would have preferred that YECL use the BCUC generic cost of capital as the appropriate point of departure."

80 Transcript Volume 2, October 8, 2008. Page 206 lines 4-7 inclusive

5.7.1.3 Cost of Debt

In its Application, YECL forecast an embedded debt cost of 7.01% for 2008 and 6.83% for 2009.[81] The embedded debt cost was calculated based on the weighted average of all debt issues. This included the actual existing historical debt issues plus the forecast amount and cost of debt to be issued in 2008 and 2009.

There was no controversy regarding the cost of the existing debt issues. However there was debate regarding the forecast cost of debt for 2008 and 2009.

Interest Rate Calculation Method

YEC took issue in argument with YECL's method of calculating the interest costs of new debt issued in 2008 and 2009. YEC indicated that YECL's method averaged the interest cost rate during the test year rather than taking into account the date that the new debt was expected to be issued. The Board notes that the Schedule 8.3 of the Application indicates that the new debt was forecast to be issued on November 20 of 2008 and 2009 and that debt in the past had often been issued on about November 20. In reply argument, YECL submitted that its mid-year rate-base method has been in place for decades and was consistent with the calculation of mid-year rate base, mid-year debt amount and mid-year work in process.

Views of the Board

The Board notes that YEC provided figures that indicated the impact of its proposed calculation method would lower the debt costs from 7.01% and 6.83% to 6.77% and 6.65% for 2008 and 2009, respectively. However, the record of the proceeding does not contain details of this calculation. Therefore, the Board did not consider this evidence as it had not been tested in the hearing.

The Board agrees with YECL that its mid-year method of calculation is consistent with past practice and is appropriate.

Forecast Debt Cost Rate

YECL forecast a cost of new debt for 2008 of 6.60%. This amount was derived as follows[82]:

Forecast Long Canada Bond Yield	4.55%
Spread	2.00
Issue Costs	0.05
Total	6.60%

YEC submitted in argument that the Canada Long Term Bond yield should be 4.2% based on "current experience" and as supported by the updated forecast for six months to June 30, 2008, of 4.1% that was provided in YEC-YECL-39(g). The Board notes that YEC-YECL-39(g) indicates the 4.1% figure was presented as an actual average yield for the first six months of 2008, and not as an "updated forecast" as YEC indicates.

[81] Application Schedule 8.1
[82] Application, page 8-2, lines 10-14

In reply argument, YEC noted that each Intervenor had raised significant concerns regarding the debt rate. YEC submitted that CW had noted that YECL had ample warning that the forecast Canada bond yields in the 2008 test year would be significantly lower than forecast in November 2007. YEC supported the reductions in debt-rate costs recommended by CW for 2008 and 2009 debt issuances.

In argument, LE submitted that the fact that the actual Canada Long Term Bonds averaged 4.1% in the first half of 2008 and the fact that CU had issued 30-year debentures on August 18 at 5.573% (which would be mirrored down to YECL at 5.623%) indicated that YECL's 2008 forecast for the Canada Long Term Bonds and for the spread were conservative (favored YECL) and called into question the forecast for 2009.

In argument, YECL noted that its actual debt-cost rate for new debt in 2008 was 5.623% but submitted that the forecast included in the Application was based on the best information available at the time and should be accepted by the Board and approved.

In argument, CW submitted that YECL should be directed to use the actual debt cost of 5.623% for 2008, since it is now known. CW disagreed that the forecast debt cost was based on the best information available. CW stated that the 4.55% long Canada forecast was based on a November 2007 forecast employed by the EUB to determine its 2008 generic cost of equity. CW submitted that the fact that the average long Canada yield during the first half of 2008 was 4.1% should have indicated by the date of filing that a downward revision to the debt cost forecast was necessary.

In its argument, CW further submitted that YECL's debt-spread forecast of 200 basis points was apparently based on ATCO Gas' GRA request and was not based on the opinion of CU's staff. CW submitted that CU's actual debt issue cost of 5.623% combined with the "… actual first quarter [2008] long term Canada yield of 4.10% would indicate that the actual premium [spread] for CU's corporate bonds is approximately 150 basis points…[83]" CW submitted that YECL had or should have had ample indication by the time of filing that its forecasted cost of debt was too high. CW indicated: "Given the current financial conditions, Ms. McShane's forecast 2009 long term Canada rate of 4.5% may not be excessive.[84]" However, CW argued that the spread should be reduced to 150 basis points "… based on the premium that CU actually commands in the financial markets.[85]" Based on the 4.5% Canada yield, the 1.50% spread and 0.05% for issue costs, CW submitted that the allowed cost rate for debt issued in 2009 should be 6.05%.

CW added that if the Board did not reduce the costs for the 2008 and 2009 new debt issues as recommended then "… YECL will have embedded in its rates on an on-going basis an extra $35,000 in debt costs that it will not actually incur.[86]"

[83] CW Argument, Section 8
[84] Ibid
[85] Ibid
[86] Ibid

In reply argument, CW reiterated its position that the 6.60% rate was not based on the best information available at the time. CW submitted that there was "… evidence that YECL knew at the time of filing that CU was actually issuing debt at a coupon rate that was well below its forecasted rate in the Application.[87]" CW cited Transcript page 178 where YECL indicated that it had discussions with CU Inc. CW also argued that it was inconsistent of YECL to request that the amount of the issue be adjusted to reflect the actual issue amount but that the issue rate should not be adjusted to actual.

UCG submitted in argument that YECL had not produced evidence that its borrowing via CU Inc. allowed for a better interest rate for YECL and that YECL had admitted that it had not inquired into interest rates from any other financial institution. UCG also noted that the evidence indicated that AE charged a 0.05% fee above the CU opportunity cost. UCG noted that YECL's costs for new loan debentures in 2005 and 2007 has been 5.23% and 5.07% respectively and that interest rates and long term government bonds have had very little variation in 2005, 2006 and 2007. UCG submitted that there was not proper evidence that the 6.6% rate from CU inc. was a fair market value cost as no other institution was approached for the opportunity to compare. UCG submitted that this suggests that the 6.6% rate is inflated and not prudent and should not be passed on to ratepayers.

In reply argument, YECL reiterated that the 6.60% debt rate was based on the "best information available at the time the Application was prepared and, in a forward Test Year approach to regulation, should be accepted by the Board as filed.[88]" YECL submitted that it is clearly the case that the mirroring down of debt costs from YECL's parent is clearly beneficial and are much more favorable than YECL could obtain on its own.

YECL said that the Board, "… must be cognizant of the fact that, while yields are indeed down, there has been an offsetting increase in spreads with the result that utilities would not be able to borrow at low rates"[89]. YECL submitted that the evidence confirms that the requested rate for the test years may be modest, if anything. YECL submitted that its requested cost of debt should be approved as filed.

Views of the Board

The first issue for the Board to determine is whether or not information related to actual debt costs in 2008 that became available after the Application was filed should be considered.

In the Board's view it may consider the best available information that is on the record. Debt costs and its components are observable in the general market and are not entirely specific to any one utility. The Board finds that it can and should consider the updated information available on the record.

[87] CW Reply, page 10
[88] YECL Reply, page 23
[89] YECL Reply, page 24

The Board reviewed the evidence regarding debt costs for 2008 and 2009 based on the information on the record.

Regarding 2008, the Board considers that YECL has confirmed that its debt costs will be 5.623%[90]. The Board is of the view that this is the best available information provided at the hearing on which to base its decision. The Board finds that YECL should use a debt rate of 5.623% for the debt issued in 2008.

Regarding 2009, the Board notes the evidence that actual government yields have declined substantially since the time of the 5.55% forecast that was used by AE. However, the Board notes that forecast debt costs for a future year are seldom exactly equal to prevailing actual debt costs when a forecast is made. The Board notes that no specific evidence regarding market forecasts of 2009 government interest rates was placed on the record or referred to in argument. The Board therefore cannot accept CW's argument that the government bond yield from the first portion of 2008 of 4.1% should be relied on as the forecast for 2009.

The Board also notes YECL's reply argument regarding the fact that increased spreads have offset the lower government yield rates.

The Board does not accept CW's argument supported by YEC that a spread of 150 basis points, based on their view of the indicated actual spread in August 2008, is appropriate. The Board notes that Intervenors did not provide evidence regarding 2009 debt-cost forecasts. Given the credit crisis and the increased spread costs which YECL has referenced, and the lack of alternative evidence regarding a forecast of 2009 interest costs, the Board accepts that YECL's forecast of 6.60% is a reasonable forecast of debt costs for 2009. The Board also notes that CW is not correct in suggesting that if actual borrowing costs turn out to be lower, then YECL will have embedded the higher costs in its rates on an ongoing basis. In fact, this rate would be updated to reflect the actual costs for purpose of future test years beyond 2009.

5.7.1.4 No Cost Capital

YECL included in its Application No Cost Capital amounts of $669,000 and $695,000 for the years 2008 and 2009 respectively. Amounts for deferred pensions including other post-employment benefit plans (OPEB) and the reserve for injuries and damages constituted the no cost capital amounts. Part of the increase for this item related to accounting for the OPEB on the cash basis starting in 2008.

Views of the Board

As there were no issues or concerns raised, the Board accepts the No Cost Capital amounts as filed.

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[90] Transcript, page 179, line 25

5.7.2 Rate Base

5.7.2.1 Capital Additions

Page 8-4 of the Application describes at a high level the drivers for capital additions. Capital additions are discussed in Section 5.8 of the Application.

5.7.2.2 Contributions

YECL stated that contributions are received from customers in accordance with the company's investment policy and included contributions of $2,560,000 and $2,506,000 for the test years 2008 and 2009 respectively.

Views of the Board

As there were no issues or concerns raised, the Board accepts the customer contribution amounts as filed.

5.7.2.3 Deferred Charges and Credits

YECL included amounts for Rate Case Reserve, Diesel Plant Major Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits.

Rate Case Reserve

YECL is proposing to use a deferral account to flow through to customers the costs associated with filing its 2008-09 GRA for both the Phase 1 and Phase II applications. YECL has forecast these costs to be $750,000 over the test years. YECL submitted that the arguments of the Intervenors did not comment materially on the Rate Case Reserve account.[91]

In its response to YEC-YECL-45(c), YECL stated:

> At the time of the 1996/97 proceeding Yukon Electrical did have a rate case reserve. In 2005, however, this treatment changed to be consistent with the treatment followed by YEC and supported in Board Order 2005-17.

In addition, YECL in its response to YEC-YECL-45(h) stated:

> To be consistent with the treatment followed by YEC in its 2005-2006 GRA and supported by the Board Order 2005-17, Yukon Electrical adjusted its treatment of rate case costs in 2005 such that it was no longer accorded deferral account treatment for the period 1998-2007.

YECL also testified that by 2005 there was about $450,000 in the Rate Case Reserve and that this reserve was for purposes of rate case issues.[92] YECL explained that the $450,000 reserve amount, "… was put into retained earning as a result of that decision [2005] which, from our perspective, as it related to 1996-97, which was a joint proceeding with joint rate hearing costs, we applied that decision to that."[93]

[91] YECL Reply, page 24
[92] Transcript p. 87
[93] Transcript p. 87

YEC submitted that YECL established a Rate Case Reserve account after the 1996-97 GRA to which it allocated approximately $75,000 each year for rate-case purposes, accumulating $450,000 by 2005.[94] YEC added that YECL, from 1996 to 2005, charged annual expenses of about $75,000 and reported such expenses annually to the Board until 2005. However, in 2005 the $450,000 in the Rate Case Reserve account of YECL was taken into retained earnings of YECL, without review or approval of the Board. YEC submitted that the Board should determine if this YECL Rate Case Reserve was properly put into retained earnings given that at the time it was a rate payer account or whether this amount should be applied to the present Application's rate-case costs.

In its argument, LE submitted that it was disturbing that about $450,000 of rate payers' contributions could be taken directly into retained earnings. LE added that this Reserve Account of ratepayers' money could pay for a large portion of the rest of this GRA for which ratepayers now have to pay again.[95]

UCG submitted that the $30,000 preliminary internal work on this GRA should be paid for by YECL rate case fund "… which Yukon Electrical now conveniently suggest is empty. This is even though Yukon Electrical has not been in front of this Board for some twelve years. If this is indeed the case, the Company should swallow this internal spending as does [sic] other parties in such processes." [96] UCG further contended that the remainder of the $720,000 be adequately broken down and identified.

Views of the Board

The Board finds that the uncontested evidence before the Board is that YECL, at the time of the 1996-97 GRA proceeding, had a deferral account, Rate Case Reserve, which by 2005 had accumulated in it the amount of $450,000. The purpose of this account was to defray the costs of rate applications. In addition, YECL never asked the Board for approval to close this deferral account. The Board is of the view that YECL had to obtain approval to withdraw funds from this account or to close the account and convert the funds to retained earnings.

The Board considered the reasons given by YECL for its action regarding the deferral account, Rate Case Reserve. The Board finds it unreasonable that YECL unilaterally decided that the closing of this account was consistent with the treatment followed by YEC in its 2005-06 GRA. YECL has not provided to the Board any explanation for this position. Also, in the Board's view, Board Order 2005-17 does not support the YECL decision in this matter as this Order related to the YEC 2005 Revenue Requirement and directed YEC to revise the amount in its cost deferral account and to include the allowed hearing costs. Further, as the account was established and by 2005 YECL had not been before the Board with a GRA for a number of years, it would have been reasonable for YECL to assume that YECL would need the funds to defray the costs of a rate case when it filed its next GRA. The Board is supported in its findings by the fact that YECL is now seeking a deferral account, Rate Case Reserve of $750,000 for the test years.

[94] YEC Argument page 46
[95] LE Argument page 9
[96] UCG Argument point 46

As a result, the Board directs YECL to re-establish the Rate Case Reserve Account with the initial balance of $450,000 carried over from 2005 as the beginning balance in 2008 and allow provisions of $150,000 for each of 2008 and 2009 to establish and ending balance in 2009 of $750,000. YECL in its refilling must adjust its revenue requirement accordingly.

Furthermore, the Board directs that YECL must, in future, make an application to this Board to apply any amounts in this account to rate-case proceedings. In general, YECL cannot dispense with any balances in deferral or reserve accounts without prior Board approval.

Regarding Diesel Plant Major Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits, the Board notes that no parties objected to these amounts; therefore, the Board accepts the amounts as filed by YECL except for the Rate Case Reserve, as noted above. The Board directs that YECL is to only use the amounts in these reserve accounts for the purposes for which they are intended. Other uses are not allowed without Board approval.

5.7.2.4 Working Capital

Working Capital amounts of $2,805,000 and $2,650,000 for 2008 and 2009 were included in the Application. No comments were received on working capital.

Views of the Board

The Board finds the working capital amounts and calculations in YECL's application to be reasonable. Therefore, the Board accepts the working capital amounts as filed.

5.8 Capital Additions

Section 9 of YECL's Application lists the capital additions for 2008 and 2009. YECL has forecast capital expenditures of $9,560,000 for 2008 and $13,504,000 for 2009. With the exception for the projects noted below, generally capital additions are for new extensions, distribution improvements, lights, meters, general plant and equipment, and generation.

Generic descriptions of each category and a listing of projects are detailed in pages 9-1 to 9-28 of the Application.

In argument, LE stated: "It is the author's view that the capital expenditures proposed in the Application are higher than is reasonable under the present circumstances[97]…" LE further recommended:

> YECL's approved capital expenditures should be reduced such that their net additions to rate base do not exceed $6.5 million per year (in other words about $9 million per year including contributions in aid of construction).[98]

[97] LE Argument, page 6
[98] Ibid, page 10

YECL in its argument said:

> Yukon Electrical submits that aside from the three projects identified above, that are new to the Test Period, it is "business as usual" for Yukon Electrical from a capital expenditure point of review. Yukon Electrical confirmed that it has available the resources necessary to complete its forecasted capital program (3T397). Yukon Electrical requests that its forecast of capital expenditures be approved as filed.[99]

Views of the Board

The Board shares the concern of LE about the level of capital projects and the ability (resource availability) of YECL to complete all the projects included in the forecast years. The Board notes that YECL's testimony is that it expects to complete the work in their capital plans in the test period.[100]

Therefore, with the exception of the projects noted below, the Board accepts the values for the remaining capital expenditures to be reasonable and consistent with past practice. The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures.

5.9 Carcross Diesel Power Plant

In its Application, YECL proposed to spend $2.0 million for a new 1.5 MW power plant to be installed at Carcross in 2009. In accordance with the Board-approved Yukon Energy Corporation 20-Year Resource Plan, YECL indicated that communities with loads over 1 MW should have local generation to serve them if the grid should stop serving the community. Of the Intervenors, only LE supported the installation of the power plant noting the frequent outages and the fact that Carcross was the only significant established community in Yukon that did not have back-up diesel generation.

In its argument, UCG submitted that there was no justification for the expenditure, noting that there was no evidence or analysis on the record related to options in lieu of purchasing the diesel unit. YEC agreed with the UCG and explained in its argument that the WAF and MD grid Community Criteria in the 20-Year Resource Plan only suggested that communities over 1.0 MW would be considered as the preferred location for new diesel units, providing grid support as well as local generation during line failures. Further, highlighting this point, YEC pointed out that there was no current need for new diesel units to meet grid system requirements.

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[99] YECL Argument, page 33
[100] Transcript Volume 3, October 9, 2008. Page 397, lines 1-6 inclusive

In argument, YECL confirmed that it was concerned with providing safe and reliable service to its customers and indicated that it had introduced Exhibit B-17 to highlight its reliability concerns and the need for backup generation. In its argument, YEC affirmed that there was no written evidence made available prior to the hearing to address local reliability concerns at Carcross and to consider options to address such concerns. YEC further argued that Exhibit B-17, which purported to justify the need for a diesel unit at Carcross by demonstrating statistics for the number of customers affected by outages, was at best misleading. Accordingly, YEC submitted that the Board should not approve the proposed Carcross diesel unit as an addition to YECL's rate base for the test years or any other near-term period.

YECL responded in reply argument that it was of the view that the approval of the Carcross generating station was necessary in order to provide an appropriate level of service to the Carcross-Tagish area. Further, all Yukon customers would benefit from the mobile nature of this standby plant. Accordingly, YECL submitted that the requested capital expenditure should be approved as filed.

Views of the Board

The Board notes LE's support of YECL's proposal to install the 1.5 MW genset in Carcross. However, the Board observes that LE in its argument indicated that YECL had neither examined alternatives nor performed a cost-benefit analysis regarding options to address reliability concerns in the area.

The Board has concerns respecting the lack of evidence on the record that YECL had explored other options with respect to mitigating the reliability in Carcross-Tagish area. The Board notes that tree-related outages have decreased noticeably since the introduction of YECL's new and improved brushing program.[101] Further, in making its finding on this issue, the Board considered proposed distribution improvement programs in the area including line relocates[102] and rebuilds[103] that include pole replacements. The Board finds that YECL has proposed these improvements to address safety and reliability issues in the Carcross-Tagish area. The Board further finds that these types of projects appear to be a reasonable alternative to YECL's proposed Carcross generator to address reliability concerns.

Considering the above, the Board is not convinced that the Carcross generator is the best option at this time to mitigate outages in the Carcross-Tagish area. Therefore, the Board does not approve the proposed Carcross diesel unit in YECL's rate base for the test years. Accordingly, the Board directs YECL in its refiling to reflect the removal of the proposed Carcross diesel unit from its proposed capital additions. Further, at the time of its next GRA, the Board directs YECL to present its business case respecting the Carcross genset if it is still the preferred option to mitigate reliability concerns in the area.

[101] YECL Argument; page 17
[102] Carcross Relocate, Application, page 9-25; Carcross Km 129-131.5, Application, page 9-18
[103] Tagish Road Rebuild, Application, page 9-18; Tagish Section to Taku 2.5 km, Application, page 9-25

In addition, the Board has concerns with YECL's response to YUB-YECL-1. YECL failed to provide recognized indicators that could be used to benchmark distribution reliability in the area and indicated that it tracks reliability on its system as a whole rather than on a line or feeder basis. Recognizing the importance of system reliability, the Board directs YECL in its next GRA to present industry recognized statistics that affirm the success of its projects and program initiatives that have safety and reliability as their basis.

Considering the number of miscellaneous pole-replacement projects YECL has proposed, the Board directs YECL to investigate the replacement of existing poles with taller poles as was suggested by LE and report back to the Board at the time of its next GRA. Further, the Board directs YECL at the time of its next GRA to provide a study that illustrates the initiatives that similar utilities (north of 60) are undertaking to address reliability concerns.

5.10 Haines Junction Diesel Plant

In argument, YECL indicated that it was very clear from the record that the rationale supporting the installation of the Haines Junction unit was as a result of extended outages and lengthy restoration times experienced with respect to this community. YECL submitted that should any residual confusion remain regarding the rationale for the installation of the Haines Junction diesel unit it has now been cleared up, as it had nothing to do with WAF grid capacity.

YEC replied that there was minimal information on the record regarding the need for the unit or any alternatives that were considered. YEC submitted that the Board should require YECL to provide such information prior to approving this unit's inclusion in rate base.

Views of the Board

The Board notes that YECL spent $542,000 on a Haines Junction diesel unit and step-up transformer bank in 1997.[104] The Board notes YECL's argument that the unit was installed to address extended outage and lengthy restoration times. The Board will allow the Haines Junction diesel plant into rate base without prejudice.

5.11 North 60 New Billing System

In its Application, YECL proposed expenditures of $1,008,000 (in 2008) for a new customer care and billing system. No business case was provided with the Application[105].

In argument, UCG noted that the billing system is over 10 years old and makes errors. UCG submitted that "the new billing system costs are not prudent and therefore should not be awarded to capital expenditures[106]."

[104] YEC-YECL-25(a)
[105] The business case was later supplied as Attachment 1 to YUB-YECL 16(b)
[106] UCG Argument, point 37

LE was surprised that a new system would cost more to operate than an existing outdated system and recommended approval of the new billing system providing that YECL gives a detailed O&M cost comparison between the current system and the proposed new system.

YECL argued that the database technology of the existing billing system was no longer economically supportable. YECL further summarized:

> Yukon Electrical confirmed that it is sharing the costs of the new billing system with the other Northwest Territories based ATCO Electric affiliates, in order to minimize costs to all ratepayers (3T337). Yukon Electrical submits that it has conducted an extensive examination to determine the most appropriate billing system for its use and has arrived at a cost effective solution that provides maximum benefits to customers[107].

In reply argument, UCG reaffirmed its argument and requested that the capital costs for this project be denied.

YEC in its reply argument said, "Of all three major capital projects included, the North of 60 Billing Project appears to have the most merit at this time, and Yukon Energy supports LE's recommendation.[108]"

YECL in its reply argument said that other than UCG no party objected to the new billing system. YECL further stated that the old billing system no longer had economies of scale and submitted that it approval should be given for this project.

View of the Board

Most parties appear to generally acknowledge that the old billing system is rapidly becoming obsolete and that past economies of scale for the operations of that system have been lost. The Board is concerned that YECL did not use an independent consultant to evaluate alternatives and make a recommendation. The use of ATCO I-Tek as the evaluator, criteria developer, and ultimately one of the vendors clouds the transparency of this decision.

The Board accepts that a new billing system is required by YECL and, absent other evidence, the evidence on the record supports YECL's choice for its new billing system. Therefore, the Board accepts the costs for a new billing system as filed.

5.12 Automated Meter Reading (AMR)

YECL included within the capital additions $330,000 in 2008 and $3,855,000 in 2009 for AMR installation. The business case for the AMR project was filed as Attachment 1 to YUB-YECL-15(c).

In argument, UCG asked that if the current meters are not broken then why is YECL required to fix them? UCG asked that the AMR costs be denied.

[107] YECL Argument, page 30
[108] YEC Reply, page 43

LE pointed out that some of the benefits listed for the project required further capital outlays. LE added that although it was stated that AMR would reduce meter reading errors, no quantifiable data was presented. According to LE, the AMR system would be more expensive to operate for the first eight years and if there was a 10% cost overrun it would be 15 years before AMR became the cost efficient alternative. LE argued that AMR was a weak project and should be deferred.

YEC argued the position that AMR is not essential, and given the requested increase in controllable costs by YECL, expenditures on AMR are not required. YECL recommended that AMR expenditures not be allowed in rate base for the test years.

CW noted that the AMR project could produce cumulative present value savings of $901,400 over 25 years based on current assumptions and savings of $550,000 and $200,500 over the same period for cost overruns of 10% and 20% respectively. CW shared the same concerns as LE regarding the purported benefits and additional expenditures to achieve those benefits. Concerns about the overstatement of benefits of the AMR project created doubts CW had about the validity of the business case. CW did not oppose approval of the project but was concerned that significant cost overruns could make the project financially unsound. Based on those concerns, CW asked that a cap be placed on the capital expenditures and the level for the cap be placed at 10% above the current estimated cost.

YECL argued that the AMR project is justified based on cost saving over the life of the project. YECL further stated that, "… implementing AMR is a business altering development[109]". The use of AMR by AE and Northwest Territories Power Corporation shows that AMR is a proven technology. YECL concluded that the record shows that AMR gives long and short term benefits to customers and should be approved as filed.

UCG replied that the costs do not warrant the benefits and therefore the cost for the project should be denied.

YEC replied that, "the AMR project is fraught with cost and other risks and lacks any justification as being required or essential for the test years[110]". YEC said it agreed with LE and UCG that the project should not be approved at this time.

In reply, YECL restated its position. YECL said the AMR project is justified solely upon economic benefits over the life of the project. YECL also said it was responsible to bring to the Board projects providing long-term benefits that extend beyond the test years. YECL rejected CW's recommendation that a cap be applied to the project.

Views of the Board

The Board has concerns with the business case for AMR. The business case has an escalation of 3% and yet YECL has asked for a 5% inflation rate over the test years. In the Board's view, several of the benefits in the business case appear overstated. That

[109] YECL Argument, page 30
[110] YEC Reply, page 43

the cross-over of the benefits is nine years away[111] puts the economic benefits of the business case at risk. Due to these concerns, the Board is not prepared to accept this project at this time and directs YECL to remove this project and its costs from rate base. The Board encourages YECL to work with all Intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Intervenors, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA.

5.13 Income Tax

In its Application, YECL made a provision for income taxes of $421,000 for 2008 and $1,060,000 for 2009. Income taxes were calculated using the flow-through method whereby taxable income is minimized by claiming the maximum of all available deductions including capital cost allowances. Future taxes are not booked[112].

YECL has requested a Tax Rate Deferral Account, arguing that income taxes are not under the control of company and not reasonably forecastable; or an error in forecasting could produce a loss or gain of a substantial magnitude[113].

In argument, LE stated that the based on his deduction, YECL is a low-risk utility and the potential deferral amount was small. In reply, LE contended that if income tax rates were going to be reduced, "(A)ny such benefit could have been passed on by including in the Application the anticipated lower tax rate or returning it in another fashion at their discretion (e.g. as no cost capital).[114]"

Views of the Board

The Board accepts the methodology used by YECL for the calculation of income taxes and expects YECL to use this method when it prepares its compliance filing. The Board is not persuaded by YECL's contention that notices of changes in tax rates are not received in sufficient time to be reasonably included in YECL's forecast. Therefore, the Board does not accept YECL's request for an income tax deferral account and directs that YECL not use such an account in its refiling.

The Board directs YECL to refile its 2008-09 revenue requirement to reflect the findings, conclusions and directions in the Reasons within 45 days of the issuance of the Order. Further, the Board directs YECL in its refiling, to provide a summary that sets out a detailed reconciliation of its requested revenue requirement for 2008 and 2009 in its Application to the revenue requirement resulting from the Board's determinations in the Reasons.

[111] The crossover can be even greater if there are cost overruns
[112] Application, page 10-1
[113] Application, page 1-5
[114] LE Reply, page 5

6. OTHER MATTERS

6.1 Independent Power Producers Policy

The Application did not contain any sections with respect to Independent Power Producers (IPPs) or Demand-Side Management (DSM). In Response to YCS-YECL-2, YECL said:

> Yukon Electrical does not have a YUB approved rate for IPP's at the present time. It may be appropriate as a starting point to consider the avoided cost of diesel fuel as one option for pricing of IPP energy. Yukon Electrical is also not aware of any legislation that exists to allow sales of energy to the electrical grid by IPP's. Until the practices and policies are created in the Yukon, Yukon Electrical encourages IPP's to focus on off loading their own power requirements which in turn results in less fuel being burned at the central generation facility.
>
> Yukon Electrical is open to discussions with any IPP who provides a safe, reliable and cost effective solution to offsetting the diesel fuel usage in the communities served by Yukon Electrical.

There were no comments in argument or reply argument on this issue.

Views of the Board

The Board notes the response by YECL to YCS-YECL-10:

> With respect to the establishment of a regulatory and legislative framework, Yukon Electrical believes that this is a critical step that has yet to take place.
>
> Should there be an interest in pursuing this topic further; Yukon electrical would be pleased to discuss it with the YUB, government as well as industry leaders.

The Board sees this as an important long-term issue, critical to security of supply in Yukon and of interest to Yukon ratepayers. Therefore, the Board directs YECL, in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to IPPs to be included as part of YECL's and YEC's next GRA.

6.2 Demand-Side Management (DSM)

The Board shares the concerns of LE submitted in argument; despite the significant fuel costs borne by all ratepayers, there are no DSM programs that reflect conservation and efficiency respecting electricity usage in communities served with isolated diesel plants. LE also noted in the YECL evidence where DSM programs were either strongly endorsed or at the least, did not provide a disincentive to a utility[115].

[115] LE Argument, page 3.

YEC in its reply argument said:

> In this context, it makes sense for the Board to consider how YECL can have an incentive to consider active and effective conservation and efficiency programs in diesel served communities[116].

YECL in its reply argument stated on page 11:

> While Yukon Electrical is always amenable to participating in such programs, its experience is that conservation and efficiency programs are typically lead by a Government based entity, in furtherance of policy objectives and not spear-headed by an individual utility. Notwithstanding, Yukon Electrical remains open to discuss such programs with the Government, YEC and customers.

Views of the Board

The Board views DSM as another critical issue for Yukon. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.

[116] YEC Reply, page 18.

7. HIGHLIGHTS OF BOARD DIRECTIONS

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

1. The Board finds, based on previous years' growth in residential customers, that the number of residential customers will increase by 1.7% in 2009. This 1.7% increase takes into account YECL's projections at the time of filing that there may be a shortage of developed lots in 2009. Accordingly, the Board directs YECL in its refiling to adjust its 2009 forecast with respect to the number of residential customer additions from 1.1% to 1.7%. To be clear, the Board directs YECL in its refiling to increase the number of residential customers to 12,908 from 12,836 currently in the forecast and to reflect this change in related schedules and its revenue requirement in the GRA. (Pages 5-6)
2. The Board directs YECL at the time of its next GRA to include comparisons of its analyses and the analyses undertaken by other utilities in Canada to arrive at sales revenue forecasts. The Board directs YECL at the time of its next GRA to include a detailed study as to what other jurisdictions consider a minimum value for R^2 that is acceptable in regression analyses. The Board directs YECL to undertake a study that compares the types of regression analyses that other utilities may use in order to arrive at their analyses. The Board is of the view that a 2% increase in YECL's residential UPC is reasonable as it appears to be the low end of the variance where actual residential UPCs exceed forecast YECL residential UPCs. Therefore, the Board directs YECL in its refiling to increase its residential UPC by 2%, and to reflect this increase in all related schedules and its revenue requirement for the test years. (Pages 6-7)
3. The Board is not persuaded that the use of a three-year average justifies a decrease in commercial average UPCs for communities outside of Whitehorse. Further, the Board has concerns with the lack of data that forms the basis of the small load commercial customers connected to the system in 2009. The Board has concerns with the difficulties that YECL experienced in obtaining monthly UPC data. Considering the above, the Board finds that the commercial UPC forecast should be increased. The Board directs YECL in its refiling to increase its commercial sales forecast by 2%. To be clear, the Board directs YECL in its refiling to increase its 2008 and 2009 MWh sales per customer to 55.7 and 55.3 respectively. Further, the Board directs YECL in its next GRA to provide a comparative study as to the analyses other utilities make use of to derive sales-revenue forecasts. (Page 8)

4. The Board finds it reasonable to amortize the increased power purchase costs directly related to the Fish Lake rebuild project over time. The Board directs YECL in its refiling to capitalize the forecast purchased power costs associated with the rebuild and to not treat these costs as an expense item in the test years. The Board further directs YECL at the time of its next GRA to provide clear documentation of these incremental power purchases from WAF due to the Fish Lake hydro rebuild. The Board approves YECL's request for continuation of the deferral accounts outlined on Page 11. The Board is concerned with the YECL's proposed Fish Lake hydro generation forecast of 6.2 GW.h for each of the test years, which is a 3.8-GW.h reduction from the 10 GW.h of generation proposed in YECL's last GRA. The Board accepts YEC's suggestion that the available generation at the Fish Lake hydro plant should be based on all years of available data. Accordingly, the Board finds 8.73 GW.h is reasonable as the base generation for the Fish Lake hydro facility, prior to considering the impact of any downtime due to the Fish Lake hydro rebuilds. Therefore, the Board directs YECL in its refilling to reflect base hydro generation of 8.73 GW.h. (Pages 10-11)

5. The Board agrees with YECL that the Pelly Crossing deferral account meets the standard criteria and is reasonable and appropriate. The Board agrees that YECL's proposal to continue a diesel fuel price rider deferral account, in order to address differences between forecast and actual fuel prices, is reasonable and appropriate. Therefore, the Board approves YECL's proposal for a diesel fuel price rider. (Page 12)

6. The Board has concerns respecting YECL's proposal for an average job-class wage increase of 9.5% for 2009 that YECL expects to result from the fall 2008 negotiations, considering the 22.5% increase in average compensation per FTE from 2007 to 2009. The Board is of the view that the proposed increases for the test period are excessive. Further, the Board finds it reasonable to approve average annual compensation increases for the test period of 6.0%. Therefore, the Board directs YECL in its refiling to reflect a compensation increase per FTE of 6.0% for each of the years in the test period. (Page 14)

7. The Board finds a vacancy rate of 3.5, the average actual vacancies for the period 2003 to 2007, to be reasonable for the test years. Therefore, the Board directs YECL in its refiling to reflect a vacancy rate of 3.5 FTEs for each of the test years. (Page 15)

8. The Board does not accept YECL's proposed 5% inflation rate for the two-year test period, as YECL has not shown it is a reasonable inflation rate. Recognizing that YECL purchases a quantum of goods and services outside of the Yukon, the Board does not agree with YEC's recommendation to approve YECL's O&M costs for revenue requirements based solely on a Yukon inflation rate of 2.5%. The Board notes CW's suggestion regarding a hybrid inflation rate comprised of Alberta and Yukon CPI rates. The Board finds it reasonable that the forecast non-labour inflation rate for 2008 and 2009 be 3.75%, which is calculated using a 50/50 weighting and inflation rates of 5.0% (Alberta) and 2.5% (Whitehorse). The Board therefore directs YECL in its refiling to reflect in its revenue requirement, an inflation rate of 3.75% for its O&M costs other than labour. The Board directs

YECL in its next GRA to provide a study that compares what other utilities use as a basis for non-labour inflation rates. (Page 16)

9. The Board finds CW's proposal to accept the I-Tek rates as final for setting information technology and customer care rates appropriate from an efficiency standpoint. Accordingly, the Board approves YECL's proposed affiliate costs subject to the proviso that the inflation rate will be adjusted to the Board-approved inflation rate for non-labour costs. The Board directs YECL in its refiling to align its proposed affiliate costs with the non-labour costs adjusted to reflect the Board-approved non-labour inflation rate. (Page 18)

10. The Board agrees with the position of YEC that the 3.8% increase for 2008 is the most accurate and up-to-date information in this proceeding. Therefore, the Board directs YECL to use 3.8% as the increase in Taxes Other Than Income for 2008 over 2007 actual costs. The Board accepts the 4% forecast increase amount over 2008 costs for 2009 costs as proposed by YECL. (Page 19)

11. With respect to FRSR, the Board is persuaded by the arguments of YEC and CW that consistency in this area is important. Given that the negative net salvage balance continues to grow, the Board does not believe that there is a need to continue to collect such amounts. YECL is to remove these amounts from its depreciation expense for each of the test years and is not to include any amounts for negative net salvage until Board approval is provided. Further, the Board orders that the December 31, 2007, accumulated amount for net negative salvage be shown as a liability and be reduced as salvage costs are incurred for the years commencing with 2008. Similar to YEC, YECL is to inform the Board and interested parties when the balance for this liability account reaches $2 million. (Page 22)

12. The Board cannot accept the equity ratio as proposed by YECL. Given current market conditions which are discussed in the Cost of Debt Section, the Board directs YECL to use the last approved equity ratio of 40%. (Page 27)

13. YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE. (Page 29)

14. The Board finds that YECL should use a debt rate of 5.623% for the debt issued in 2008. (Page 33)

15. As there were no issues or concerns raised, the Board accepts the No Cost Capital amounts as filed. (Page 33)

16. As there were no issues or concerns raised, the Board accepts the customer contribution amounts as filed. (Page 34)

17. The Board directs YECL to re-establish the Rate Case Reserve Account with the initial balance of $450,000 carried over from 2005 as the beginning balance in 2008 and allow provisions of $150,000 for each of 2008 and 2009 to establish and ending balance in 2009 of $750,000. YECL in its refilling must adjust its revenue requirement accordingly. Furthermore, the Board directs that YECL must, in future, make an application to this Board to apply any amounts in this account to rate-case proceedings. In general, YECL cannot dispense with any balances in deferral or reserve accounts without prior Board approval. Regarding Diesel Plant Major

Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits, the Board accepts the amounts as filed by YECL except for the Rate Case Reserve. The Board directs that YECL is to only use the amounts in these reserve accounts for the purposes for which they are intended. Other uses are not allowed without Board approval. (Page 36)

18. The Board finds the working capital amounts and calculations in YECL's application to be reasonable. Therefore, the Board accepts the working capital amounts as filed. (Page 36)

19. With the exception of the projects noted, the Board accepts the values for the remaining capital expenditures to be reasonable and consistent with past practice. The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures. (Page 37)

20. The Board finds that YECL has proposed improvements to address safety and reliability issues in the Carcross-Tagish area. The Board further finds that these types of projects appear to be a reasonable alternative to YECL's proposed Carcross generator to address reliability concerns. The Board is not convinced that the Carcross generator is the best option at this time to mitigate outages in the Carcross-Tagish area. Therefore, the Board does not approve the proposed Carcross diesel unit in YECL's rate base for the test years. Accordingly, the Board directs YECL in its refiling to reflect the removal of the proposed Carcross diesel unit from its proposed capital additions. Further, at the time of its next GRA, the Board directs YECL to present its business case respecting the Carcross genset if it is still the preferred option to mitigate reliability concerns in the area. The Board directs YECL in its next GRA to present industry recognized statistics that affirm the success of its projects and program initiatives that have safety and reliability as their basis. The Board directs YECL to investigate the replacement of existing poles with taller poles as was suggested by LE and report back to the Board at the time of its next GRA. Further, the Board directs YECL at the time of its next GRA to provide a study that illustrates the initiatives that similar utilities (north of 60) are undertaking to address reliability concerns. (Page 38)

21. The Board notes that YECL spent $542,000 on a Haines Junction diesel unit and step-up transformer bank in 1997. The Board notes YECL's argument that the unit was installed to address extended outage and lengthy restoration times. The Board will allow the Haines Junction diesel plant into rate base without prejudice (Page 39)

22. The Board accepts that a new billing system is required by YECL and, absent other evidence, the evidence on the record supports YECL's choice for its new billing system. Therefore, the Board accepts the costs for a new billing system as filed. (Page 40)

23. The Board is not prepared to accept the AMR project at this time and directs YECL to remove this project and its costs from rate base. The Board encourages YECL to work with all Intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Intervenors, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA. (Page 42)
24. The Board accepts the methodology used by YECL for the calculation of income taxes and expects YECL to use this method when it prepares its compliance filing. The Board is not persuaded by YECL's contention that notices of changes in tax rates are not received in sufficient time to be reasonably included in YECL's forecast. Therefore, the Board does not accept YECL's request for an income tax deferral account and directs that YECL not use such an account in its refiling. (Page 42)
25. The Board directs YECL to refile its 2008-09 revenue requirement to reflect the findings, conclusions and directions in the Reasons within 45 days of the issuance of the Order. Further, the Board directs YECL in its refiling, to provide a summary that sets out a detailed reconciliation of its requested revenue requirement for 2008 and 2009 in its Application to the revenue requirement resulting from the Board's determinations in the Reasons. (Page 42)
26. The Board directs YECL, in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to IPPs to be included as part of YECL's and YEC's next GRA. (Page 43)
27. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory. (Page 44)

NON-CONFIDENTIAL

Request IR-9:

With reference to Appendix B of the testimony of Ms. Kathleen C. McShane, please provide copies of all studies that indicate that the long-term GDP growth rate is an appropriate measure of long-term growth in earnings and dividends for utility companies.

Response IR-9:

Ms. McShane is not aware of any specific studies that indicate GDP growth is an appropriate measure of long-term growth in earnings and dividends for utility companies. As noted at page B-2 of Ms. McShane's testimony, the use of forecast GDP growth as the proxy for the rate of growth to which companies will migrate over the longer term is a widely utilized approach. It is commonly used for the purpose of estimating the DCF cost of equity for regulated companies. It has been used by the FERC as a standard input into the estimation of the DCF cost of equity for pipelines since its 1997 contemporaneous orders for Northwest Pipeline Corp. and Williston Basin Interstate Pipeline Co. (Opinion No. 396-B, Northwest Pipeline Corp., 79 FERC 61,309, at pp. 62,380-82, reh'g denied, 81 FERC 61,036 (1997)) and Williston Basin Interstate Pipeline Co., (79 FERC 61,311, at pp. 62,387-88, reh'g denied, 81 FERC 61,033 (1997)). In Order No. 396-B, the FERC noted that investment houses use GDP growth as the steady state growth rate and that it is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it somewhat during bad periods.

The growth component of a DCF model is intended to be an estimate of what investors expect the firm's long-term growth rate to be and thus is built into the prices they are willing to pay (and is therefore embedded in the dividend yield component of the model). Ms. McShane's use of forecast long-term growth in the economy as a reasonable estimate of investors' expectations for long-term growth in earnings for mature industries is based on the link between corporate profits and GDP growth in the long-term. The two primary determinants of profit growth are growth in nominal GDP and unit labour costs. Nominal GDP measures the current dollar value of the goods and services produced in the economy. Simplistically, corporate profits reflect GDP less payments to labour, depreciation, plus income from abroad. As long as labour costs are contained, increases in economic growth will be reflected in growth in profits. To Ms. McShane’s knowledge, the conclusion that corporate profit growth will track GDP growth in the long-term is not contested.

NON-CONFIDENTIAL

Request IR-10:

Please provide the following documents relevant to NSPI's fuel and generation-operation data from 2013 GRA.

(a) 2013 GRA OP-05 Attachment 1

(b) 2013 GRA OP-08 Attachment 1

(c) 2013 GRA Load/Fuel Update OP-05 Attachments 1 and 2.

(d) 2013 GRA Load/Fuel Update OP-08 Attachment 1

(e) 2013 GRA Load/Fuel Update OE-01A, Attachments 1–6.

(f) 2013 GRA Load/Fuel Update OE-01B, Attachment 1.

(g) 2013 GRA Load/Fuel Update OE-01C Attachments 1 and 2.

(h) 2013 GRA Load/Fuel Update OE-01D Attachments 1 and 2.

(i) 2013 GRA Load/Fuel Update OE-01H Attachments 1 and 2.

(j) 2013 GRA Load/Fuel Update OE-01K Attachments 1 and 2.

(k) 2013 GRA Load/Fuel Update OE-01L Attachment 1.

(l) 2013 GRA Load/Fuel Update OE-01N Attachment 1.

NON-CONFIDENTIAL

(m) 2013 GRA Load/Fuel Update OE-01O Attachment 1.

(n) 2013 GRA Load/Fuel Update OE-01Q Attachment 1.

Response IR-10:

(a-n) These documents are available at the UARB website under matter M04972:

http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

CONFIDENTIAL (Partial Attachment Only)

Request IR-11:

Please provide 2013 COSS CA DR-12 Attachment 1 from the current COSS consultation process.

Response IR-11:

Please refer to Partially Confidential Attachment 1.

2013		MW	Ccapacity	Minimum	AGC	%	Average	Forecatsed Generation (Hydro/Wind) - GWh											
Generator	Type	Capacity	Factor	Stable MW	Capable	DAFOR	Heat Rate												
								Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01 - Lingan #1	coal	153	30%	[redacted]	Yes	[redacted]													
02 - Lingan #2	coal	153	17%	[redacted]	Yes	[redacted]													
03 - Lingan #3	coal	153	78%	[redacted]	Yes	[redacted]													
04 - Lingan #4	coal	153	12%	[redacted]	Yes	[redacted]													
05 - Pt Aconi #1	coal	171	90%	[redacted]	No	[redacted]													
06 - Pt Tupper #2	coal	152	64%	[redacted]	Yes	[redacted]													
07 - Trenton #5	coal	150	45%	[redacted]	Yes	[redacted]													
08 - Trenton #6	coal	157	100%	[redacted]	Yes	[redacted]													
09 - Tufts Cove #1 - G	Nat Gas	81	51%	[redacted]	No	[redacted]													
10 - Tufts Cove #2 - G	Nat Gas	93	65%	[redacted]	Yes	[redacted]													
11 - Tufts Cove #3 - G	Nat Gas	147	95%	[redacted]	Yes	[redacted]													
12 - Tufts Cove #4	Nat Gas	49	-	[redacted]	Yes	[redacted]													
13 - Tufts Cove #5	Nat Gas	49	-	[redacted]	Yes	[redacted]													
14 - Tufts Cove #6	Nat Gas CC	150	73%	[redacted]	Yes	[redacted]													
15 - Burnside #1	Deisel	33	0%	[redacted]	Yes	[redacted]													
16 - Burnside #2	Deisel	33	0%	[redacted]	Yes	[redacted]													
17 - Burnside #3	Deisel	33	0%	[redacted]	Yes	[redacted]													
18 - Burnside #4	Deisel	33	0%	[redacted]	Yes	[redacted]													
19 - Tusket #1 CT	Deisel	25	0%	[redacted]	Yes	[redacted]													
20 - Victoria Junction #1	Deisel	33	0%	[redacted]	Yes	[redacted]													
21 - Victoria Junction #2	Deisel	33	0%	[redacted]	Yes	[redacted]													
22 - Grand Etang	Wind	0.7	30%	-	-	-	-	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
23 - Little Brook	Wind	0.6	30%	-	-	-	-	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
24 - Nuttby mountain	Wind	45.0	36%	-	-	-	-	12.8	12.3	14.8	12.4	11.1	8.4	8.3	7.8	9.2	13.9	14.5	14.8
25 - Gulliver Cove	Wind	30.0	42%	-	-	-	-	10.0	9.6	11.7	9.8	8.7	6.6	6.5	6.2	7.3	10.9	11.4	11.6
H01 - Wreck Cove	hydro	212.0	13%	[redacted]	Yes	-	-	32.3	21.0	20.7	23.4	42.3	20.9	28.0	18.9	15.4	25.3	21.7	35.1
H02 - Annapolis	Tidal	20.0	12%	-	No	-	-	2.1	2.1	2.5	2.5	2.6	2.5	2.7	2.1	2.3	2.1	1.9	2.2
H03 - Avon	hydro	6.8	32%	-	Yes	-	-	3.2	2.1	3.6	3.1	2.0	1.7	0.8	0.4	0.7	2.0	2.1	3.3
H04 - Black River	hydro	22.5	38%	-	Yes	-	-	13.0	9.8	14.2	10.7	7.7	4.6	3.0	2.3	3.7	7.0	8.9	12.3
H05 - Nictaux	hydro	8.3	46%	-	Yes	-	-	5.8	5.3	6.0	5.8	4.5	1.8	1.0	0.8	0.2	0.8	5.1	6.0
H06 - Lequille	hydro	11.2	21%	-	Yes	-	-	2.1	1.7	4.2	3.2	1.4	0.5	1.1	1.1	0.4	2.9	4.0	3.8
H07 - Paradise	hydro	4.7	40%	-	Yes	-	-	3.0	2.7	3.1	2.9	2.5	0.7	0.6	1.1	0.9	0.9	0.8	2.3
H08 - Mersey	hydro	42.5	48%	-	Yes	-	-	26.9	24.1	25.9	24.4	19.6	18.1	10.4	12.4	12.2	13.8	19.6	24.2
H09 - Sissiboo	hydro	24.0	27%	-	Yes	-	-	7.6	6.0	9.4	8.6	7.8	5.0	3.5	2.4	3.3	6.6	5.6	9.1
H10 - Bear River	hydro	13.4	24%	-	No	-	-	3.9	3.4	4.3	4.5	3.7	3.4	3.2	1.7	0.9	1.4	2.6	3.2
H11 - Tusket hydro	hydro	2.4	42%	-	No	-	-	1.4	1.2	1.6	0.9	0.8	0.5	0.5	0.4	0.4	1.0	1.2	1.4
H12 - Roseway/Harmony	hydro	1.8	22%	-	No	-	-	0.7	0.5	0.7	1.4	0.8	0.0	0.0	0.0	0.0	0.0	0.1	0.4
H13 - St. Margaret's	hydro	10.8	22%	-	No	-	-	2.6	2.7	3.5	3.4	2.3	0.6	0.7	0.6	1.5	1.9	3.4	3.5
H14 - Sh. Harbour	hydro	10.8	35%	-	No	-	-	4.8	2.8	5.3	4.0	3.3	2.8	3.3	2.9	1.3	3.9	4.6	4.5
H15 - Dickie Brook	hydro	3.8	19%	-	No	-	-	0.7	1.1	1.0	0.9	0.8	0.8	0.7	0.3	0.3	0.4	0.6	0.7
H16 - Fall River	hydro	0.5	40%	-	No	-	-	0.2	0.2	0.4	0.2	0.2	0.1	0.1	0.1	0.0	0.1	0.3	0.4
IPP01-Pubnico	wind	30.6	33%	-	-	-		[redacted]											
IPP02-Lingan	wind	14.0	34%	-	-	-		[redacted]											
IPP03-Glace Bay	wind	0.8	35%	-	-	-		[redacted]											
IPP04-Donkin	wind	0.8	36%	-	-	-		[redacted]											
IPP06-Tiverton	wind	0.9	19%	-	-	-		[redacted]											
IPP07-Springhill	wind	2.1	28%	-	-	-		[redacted]											
IPP08-Higgins Mountain	wind	3.6	22%	-	-	-		[redacted]											
IPP09-Goodwood	wind	0.6	19%	-	-	-		[redacted]											
IPP10-Brookfield	wind	0.6	15%	-	-	-		[redacted]											
IPP11-Fitzpatrick	wind	1.6	28%	-	-	-		[redacted]											
IPP12-Point Tupper 1	wind	0.8	29%	-	-	-		[redacted]											
IPP13-Digby	wind	0.8	28%	-	-	-		[redacted]											
IPP14-Tatamagouche	wind	0.8	21%	-	-	-		[redacted]											

2013		MW	Ccapacity	Minimum	AGC	%	Average	Forecatsed Generation (Hydro/Wind) - GWh											
Generator	Type	Capacity	Factor	Stable MW	Capable	DAFOR	Heat Rate												
								Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IPP15-Amherst	wind	30.0	33%	-	-	-		[redacted]											
IPP16-Dalhousie	wind	51.0	38%	-	-	-		[redacted]											
IPP17-Glen Dhu	wind	60.0	31%	-	-	-		[redacted]											
IPP18-Maryvale	wind	6.0	28%	-	-	-		[redacted]											
IPP19-Bear Head	wind	22.0	34%	-	-	-		[redacted]											
IPP20-Watts	wind	1.5	33%	-	-	-		[redacted]											
IPP21-Fairmount	wind	4.0	36%	-	-	-		[redacted]											
IPP22-Dunvegan	wind	2.0	0%	-	-	-		[redacted]											
IPP23-Granville Ferry	wind	2.0	22%	-	-	-		[redacted]											
IPP24-Isle Madamme	wind	2.0	0%	-	-	-		[redacted]											
IPP25-Craegnish	wind	6.0	6%			-		[redacted]											
IPP26-Irish Mountain	wind	6.0	6%	-	-	-		[redacted]											
IPP27-Cape Mabou	wind	6.0	6%	-	-	-		[redacted]											
IPP28-Spiddle Hill	wind	0.8	36%	-	-	-		[redacted]											
IPP29-Cape North	wind	0.7	35%	-	-	-		[redacted]											
IPP30-Donkin (CP)	wind	1.6	48%	-	-	-		[redacted]											
IPP31-Sackville Landfill	landfill gas	2.0	52%	-	No	-		[redacted]											
IPP32-Black River	hydro	0.2	85%	-	No	-		[redacted]											
IPP33-Brooklyn Power	biomass	23.4	72%	-	No	-		[redacted]											
IPP34-Morgan Falls	hydro	0.5	33%	-	No	-		[redacted]											
IPP35-Taylor Lumber	biomass	0.8	67%	-	No	-		[redacted]											

NON-CONFIDENTIAL

Request IR-12:

Please provide the following power-plant data:

(a) 2013 ACE SBA IR-38 Attachment 1

(b) 2013 ACE NSPI (NSUARB) IR-15

Response IR-12:

(a-b) The 2013 ACE Plan process is an open matter (M05339) before the UARB. The requested documents can be accessed at the Board's website: http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

NON-CONFIDENTIAL

Request IR-13:

Please provide 2013 ACE SBA IR-95 Attachment 1, and in addition:

(a) Please provide an update of this Attachment with forecast 2020 loads, non-Maritime Link transmission additions, and existing and currently expected generation in Nova Scotia.

(b) Please provide an update of this Attachment with forecast 2020 loads and transmission additions and the Maritime Link operating at 150 MW input.

(c) Please provide an update of this Attachment with forecast 2020 loads and transmission additions and the Maritime Link operating at 300 MW input.

(d) Please provide an update of this Attachment with forecast 2020 loads and transmission additions and the Maritime Link operating at 500 MW input.

Response IR-13:

(a-d) Please refer to SBA IR-95. This analysis was not performed in preparation of the Application.

NON-CONFIDENTIAL

Request IR-14:

Please provide the heat rate data and projections from:

(a) 2013 GRA Load/Fuel Update OP-06 Attachment 1

(b) 2013 GRA Load/Fuel Update OP-06

Response IR-14:

(a-b) Please refer to CA IR-10.

NON-CONFIDENTIAL

Request IR-15:

Please provide all data provided to Power Advisory LLC by NSPI & NSPML for the NSDOE report "Analysis of Proposed Development of the Maritime Link and Associated Energy from Muskrat Falls Relative to Alternatives," January 16, 2013.

Response IR-15:

The above-noted report is not in evidence in this proceeding and neither NS Power nor NSPML is the author or sponsor of the report. Questions relating to the report should be directed to the author or sponsor of the report.

NON-CONFIDENTIAL

Request IR-16:

Please provide the "information provided by NS Power" to Power Advisory LLC that "the province's transmission system can safely take up to 300 MW through the Maritime Link. Imports above this level would require significant system upgrades." ("Analysis of Proposed Development of the Maritime Link," pp. 18–19)

Response IR-16:

Please refer to CA IR-15.

NON-CONFIDENTIAL

Request IR-17:

Please provide any communications between Power Advisory and NSPI regarding Power Advisory's report "Analysis of Proposed Development of the Maritime Link."

Response IR-17:

Please refer to CA IR-15.

NON-CONFIDENTIAL

Request IR-18:

Please provide all data and documents provided by NSPI to the REA (other than the bids that NSPI filed with other parties) in the development of the Renewable Energy RFP, including but not limited to, data on:

(a) Wind integration costs,

(b) The relative energy and capacity value of generators with ERIS interconnection, and

(c) Zonal transmission constraints.

Response IR-18:

The REA RFP is out of scope for this proceeding. REA related proceedings are accessible on the UARB website at http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

NON-CONFIDENTIAL

Request IR-19:

If NSPI did not provide the REA with information comparable to Appendix 6.02, please explain why NSPI failed to provide such information.

Response IR-19:

Please refer to CA IR-18.

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Request IR-20:

Reference Exhibit M-2, Appendix 6.03, p. 13.

(a) Please provide all available documentation of the "long term update July/Aug 2012" forecast of natural gas prices.

(b) If the NSPI Fuels Group has updated its long-term forecast of natural gas prices since the "long term update July/Aug 2012" forecast, please provide:

(i) The most recent forecast of annual prices at the Henry Hub, at Dracut, and delivered to Tuft's Cove.

(ii) All available documentation of the most recent forecast of natural gas prices.

Response IR-20:

(a) Please refer to Liberty IR-5.

(b) The NS Power Fuels Group has not updated its long-term forecast of natural gas prices since this data was provided.