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Request IR-1:

With respect to the Opinion of Capital Structure and Return on Equity, prepared by Ms. Kathleen C. McShane, please provide:

(a) Copies of all source documents, articles, cited documents listed in footnotes, regulatory decisions, work papers, and other sources used in the development and preparation of the testimony and appendices of Ms. McShane; and

(b) An index with files names and/or page or tab numbers associated with the materials provided in (1).

Response IR-1:

(a-b) The requested documents and work papers are listed below. If the information is provided in response to another question, the relevant response is listed below under "File Name":

Reference/ Line Nos.	Please refer to	File
Footnote 3	Attachment 1	S&P OPG Hydro One Gov Support 10 2005
Footnote 4	Attachment 2	Bluefield Water Works 1923
Footnote 4	Attachment 3	HOPE NATURAL GAS
Footnote 4	Attachment 4	North-western 1929
88 to 91, FN 5	Attachment 5	WEO 2011 Figure 2.20
91 to 93, FN 6	Attachment 6	Conf Brd Shedding Light 2012
142-143	Attachment 7	ATCO Electric AUC Rule 005 Filing 2011 Schedule 2T
142-143	Attachment 8	AltaLink AUC Rule 005 Filing 2011 Schedule 2
143	Attachment 9	AUC Decision 2011-474
146	Attachment 9	
Footnote 8	Attachment 10	S&P AltaLink Nov 2012
151-153	Attachment 11	AUC Decision 2004-052

Reference/ Line Nos.	Please refer to	File
Footnote 9	Attachment 9	
Footnote 10	Attachment 12	OEB Decision EB-2006-0501
181-182	Attachment 13	Moodys ATC 2012.
181-182	Attachment 14	S&P ATC 2012
Footnote 11	Attachment 15	S&P Peer Comparison 2006
198-200	Attachment 16	NEB GH-6-96 Maritimes and Northeast
198-200	Attachment 17	NEB GH-3-97 Alliance
198-200	Attachment 18	NEB OH-3-2007 Southern Lights
200-201	Attachment 19	DBRS Alliance 2012
200-201	Attachment 20	DBRS M&NP 2012
200-201	Attachment 21	S&P Alliance 2012
200-201	Attachment 22	S&P M&NP 2012
218-220	Attachment 23	Decision 2012 NSUARB 227
Footnote 14	Attachment 24	work paper footnote 14
Footnote 15	Attachment 25	OEB Report of Board 2009
Footnote 15	Attachment 26	OEB EB 2010-0002.
Footnote 15	Attachment 27	OEB Letter COC Parameters for 2012.
Footnote 15	Attachment 28	OEB Letter COC Parameters for 2013
Footnote 16	Attachment 9	
255-265	Attachment 29	Conf Brd Electricity Restructuring 2004
Footnote 17	Energy Policy Act 2005 http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf	
Footnote 18	Attachment 31	FERC Order 679
Footnote 18	Attachment 32	FERC Order 679A
Footnote 18	Attachment 33	FERC Order 679B
Footnote 18	Attachment 34	FERC 2012 Policy Statement
Footnote 20	Attachment 35	FERC RITELine
320-325	Attachment 36	Work paper weighted roe
Footnote 22	Attachments 18, 19 and 20	

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Reference/ Line Nos.	Please refer to	File
330-331	CA IR-5	
339	CA IR-3	
412	CA IR-3	
Footnote 24	CA IR-3	
Footnote 25	Attachment 25	
Footnote 26	Attachment 37	Regie D-2010-147 Gazifere 2010
Footnote 26	Attachment 38	Regie D-2011-182 Gaz Metro 2011
Footnote 27	Please refer to CA IR-3.	
Footnote 28	Please refer to CA IR-3.	
514 to 517	Please refer to CA IR-3.	
App. B - utility selection	Please refer to CA IR-5.	
Table B-1	Please refer to CA IR-5.	
App. B - price and dividend info	Please refer to CA IR-3.	
App. B page B-6	Please refer to CA IR-3.	
Table B-2	Please refer to CA IR-3.	
App. B - 3 stage growth model	Please refer to CA IR-3.	
Table B-3	Please refer to CA IR-3.	
App.B, regression and FN 5	Please refer to CA IR-3.	
Table B-4	Please refer to CA IR-3.	

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Credit FAQ: Implied Government Support As A Rating Factor For Hydro One Inc. And Ontario Power Generation Inc.

Publication date: 20-Oct-2005
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The rating action by Standard & Poor's Ratings Services on electricity generator Ontario Power Generation Inc. (OPG; BBB+/Positive/--) on Sept. 27, 2005, incorporates the application of its government support methodology and highlights circumstances where the level of implied government support can differ between related entities.

This credit FAQ will help users of the ratings understand Standard & Poor's approach to rating government-related issuers by providing an explanation of the criteria and how and what level of implied government support is factored into ratings. Furthermore, an explanation of the level of support factored into the rating on OPG and why it differs from that assigned to its sister company, the electricity transmission and distribution utility, Hydro One Inc. (A/Stable/A-1), is provided. The article also looks at circumstances where the support might change over time.

Hydro One and OPG are both wholly owned by the Province of Ontario (AA/Stable/A-1+). The Ontario Energy Board (OEB) independently regulates Hydro One, while the provincial government sets the current prices received for the bulk of OPG's generation output, and has established legislation whereby the bulk of OPG's assets will move to independent regulation over time.

Frequently Asked Questions

When and how does Standard & Poor's factor government support into a rating?

Essentially the issue of rating support for government-owned entities falls into three broad categories. The categories, ratings treatment, basis for classification, and some examples in the Canadian market of the classification are outlined in table 1. In none of these cases is direct or percentage ownership the determining factor to the degree of expected support.

Table 1

Broad Categories of Government-Supported Entities

Category	Ratings Treatment	Basis of Classification	Examples
1	Appropriate to equalize the rating on the entity with the rating on the government.	Where a business unit or entity is viewed as highly aligned and integral to the government's policy directives and finances.	The corporate credit rating on Chatham Kent Energy Inc. is equalized with that of its owner, the Municipality of Chatham-Kent. Other examples include the equalizing of the ratings on the debt issued by Hydro Quebec and Newfoundland and Labrador Hydro with that of their provincial owners based on explicit and unconditional guarantees, although other obligations of the utilities are not explicitly guaranteed.
2	In these instances the corporate credit rating on the entity is notched off the rating on the government from one to six notches.	Entities that have a defined public policy role in which the government defines their performance and prospects. Support is both a matter of policy and law with support expressed through statutory or ultimate –	The ratings on the University Health Network, York University, and the York Region District School Board are notched off the rating on the Province of Ontario.

		rather than timely – guarantees.	
3	Rather than a notching down from the rating on the government, the rating is notched up from the stand-alone rating on the company and could be notched up one, two, or three notches.	Where the relationship is supportive and often enhances the entity's underlying credit strengths through helpful policies and the possibility of direct assistance.	Globally this category includes the majority of rated and unrated government-supported entities and it is within this category that Hydro One and OPG sit.

Whether the corporate or debt ratings on a government-owned entity reflect explicit or implied support from its owner, and the extent to which the ratings might benefit, depends on the application of Standard & Poor's rating methodology as it applies to government-owned entities. For detailed information on the criteria, please refer to "Revised Rating Methodology For Government-Supported Entities" published June 5, 2001, on RatingsDirect, Standard & Poor's Web-based credit research and analysis system, at www.ratingsdirect.com.

Why do Hydro One and OPG fall into Category 3?

Some of the reasons why Hydro One and OPG do not fall into the first and second categories but into the third category include the following. There is no formal guarantee of Hydro One and OPG obligations by the province; they are not government departments, ministries, or agencies; and the two companies play a relatively minor part in the province's finances. As such, Category 1 is not appropriate. The lack of explicit statements of support through policy and law, lack of a defined public policy role for both businesses, and a desire by the government that both businesses act as stand-alone commercial operations, means Category 2 is not appropriate either. It could be argued that OPG falls into Category 2, given its current role as a means of government influence on the mix of generation in Ontario (that is, the phasing-out of coal-fired generation) and on the price of power paid by households, but under current government policy OPG is expected to increase its financial independence from the government, and the government is expected to distance itself from the oversight of the company as it transitions to regulatory oversight by the OEB. Moreover, there is an expectation OPG will continue to be part of a market-based electricity sector in Ontario. The third category, in which Hydro One and OPG sit, is appropriate given the ability of both companies to operate independently of government, while the government retains the ability to reduce business risks for the two companies, to varying degrees, and provide direct assistance if required.

What is the basis of Standard & Poor's approach to government-owned entities?

Standard & Poor's assigns ratings taking a long-term view of credit, and while it appears remote the government of Ontario will not remain the 100%-owner and supporter of Hydro One and OPG for the foreseeable future, circumstances can and do change. It 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 rather 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.

Hydro One and OPG are not viewed as being so integrated with government to warrant equalization of the ratings or for the ratings to be notched off from that on the province. Furthermore, the two businesses can operate independently from government and are expected to act commercially and be financially sustainable, although OPG will continue to source the bulk of its debt funding from the provincial government for some time yet. The recent OPG board independent decision not to proceed with further refurbishments of its Pickering nuclear plant is evidence of a move to a more autonomous OPG. The government does not offer, and is reluctant to offer, implicit government guarantees or financial support for the obligations of Hydro One or OPG. Furthermore, to equate the ratings on Hydro One and OPG with that of the rating on the province or to assign a rating close to that assigned to the province introduces a credit cliff in the event of a material change in circumstances. It must be remembered that it was not so long ago that these two entities were both the subject of proposed initial public offerings. From Standard & Poor's perspective, to notch up from the stand-alone rating provides greater transparency and stability to the ratings for existing and potential holders of Hydro One and OPG's long-term bonds.

What level of government support is factored into the ratings on Hydro One and OPG?
The long-term rating on Hydro One benefits from one notch of implied government support, while the long-term corporate credit rating on OPG benefits from two notches.

Both entities are strategic within the economy, and the government has demonstrated willingness to financially assist both businesses. OPG has no long-term public debt, with the government continuing to hold notes payable of C$3.9 billion from OPG as of June 30, 2005.

What explains the difference in the level of implied support assigned to Hydro One and OPG?
The difference in implied support between the two provincial owned entities comes down to the degree of control and influence the government has over each company's financial well-being. Although the government of the day can ultimately bring forth legislation for whatever changes it feels appropriate for the long-term structure of Hydro One, OPG, and the Ontario regulatory framework and market structure, the ability of the government to readily influence and control the two companies' financial position in the short term is not the same.

The potential ease and timeliness by which the government can take action to support OPG relative to Hydro One contribute to the difference in the level of notching. There are three primary support mechanisms that highlight the greater likelihood and ease with which the government is able to support OPG's creditworthiness, namely the provision of financing, the degree of corporate oversight, and the transitional regulatory framework. The provincial government is currently the key debt provider for OPG but not for Hydro One. Hydro One's C$5.5 billion in debt funding as of June 30, 2005, was raised through the public capital market. The rigor with which the government oversees Hydro One does not appear to be as intrusive as it is with OPG. Furthermore, the provincial government is the direct current price-setter for OPG's generation output--both regulated and unregulated, while there are established processes by an arm's-length regulator for setting Hydro One's distribution and transmission tariffs.

The government's current position as the determiner of OPG's regulated and nonregulated generation prices and key financier means that the instruments or mechanisms at its control to help (or hinder) OPG operationally and financially are more readily available than with Hydro One. As a consequence, the government has a big influence on OPG's financial performance through its ability to determine what returns the company will earn, what debt it will assume, and in some cases what new major capital expenditure will be undertaken. Despite the government influence in setting prices for OPG's regulated generation, recent legislation permits the company to apply to the provincial regulator, the OEB, to seek variance accounts for extraordinary costs, and to apply for a change to the current government-imposed prices. Of issue for this course of action are the unproven process and timing involved. Furthermore, regardless of potential change in prices by the OEB, the government retains its price-setting autonomy for OPG's nonregulated generation. As such, the shareholder has more levers at its disposal to influence the company financially in a timely fashion relative to those by which it can influence Hydro One. Hydro One is largely beholden to the independent provincial regulator in terms of its operational performance and returns, and in addition to oversight by its shareholder, Hydro One is subject to the scrutiny and disclosure requirements of the debt capital markets. Furthermore, any material financial support provided to Hydro One in times of financial stress beyond an initial and immediate suspension or deferral of dividends, would most likely involve direct cash equity injections or short-term financing and in doing so, would introduce administrative and political elements into decision making that increase the risk of inadequate or less timely support.

Will the level of implied support incorporated into the ratings remain consistent over time?

The simple answer is no. It might, but a number of elements dictate whether the implied government support and the level of support is appropriate, and as such, a change in circumstances can lead to a change in the level of support and the rating assigned. A more obvious example would be a change in ownership. Assuming a new owner has a neutral impact on Hydro One or OPG's creditworthiness, the ratings on these two businesses would likely gravitate to the stand-alone ratings. Conversely, a new owner might also have a positive or negative influence on the issuer ratings if fully consolidated with that of the new owner. It can be expected that in the event of a foreshadowed sale or IPO, the ratings would be adjusted to reflect the changing circumstances in advance of the execution of the sale.

Less obvious developments could also change the level of implied support, particularly that assigned to OPG. The basis on which the level of government support for OPG is differentiated from Hydro One could change over time and lead to the level of implied support assigned to OPG moving to be more in line with the one notch incorporated into the Hydro One rating, barring any change in ownership. In the next few years, OPG is expected to move to a situation where it will operate in a manner and environment more in line with that in which Hydro One now finds itself. The company will likely be largely regulated by an independent regulator, may issue debt in its own right, and may not be subject to the same level of government oversight and directives that it currently is. Under these circumstances, the provincial government is unlikely to exert the same influence and control over OPG's operational and financial direction and it would be appropriate to revisit the level of support at that time. Of comfort to future bondholders, however, is that if such an environment transpires as expected, OPG's underlying creditworthiness would likely also improve such that the potential scaling-back of the level of implied support would be unlikely to alter the corporate credit rating on OPG. The expectation of changing circumstances and a change in the relationship are also the main reasons the level of support factored into the rating on OPG is not to the full extent of the three notches that the criteria allows for entities which fall into Category 3.

U.S. Supreme Court

BLUEFIELD WATER WORKS CO. v. PUBLIC SERVICE COMMISSION, 262 U.S. 679 (1923)

262 U.S. 679

BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

[262 U.S. 679, 680] Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.

Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

[262 U.S. 679, 683]

Mr. Justice BUTLER delivered the opinion of the Court.

Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See Oklahoma Natural Gas Co. v. [262 U.S. 679, 684] Russell, 261 U.S. 290 , 43 Sup. Ct. 353, 67 L. Ed. --, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U.S. 287 , 40 Sup. Ct. 527.

2. The commission fixed $460,000 as the amount on which the comp ny is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer on basis of reproduction new, less depreciation, at prewar prices $ 624,548 00 b. Estimate by company's engineer on basis of reproduction new, less depreciation, at 1920 prices 1,194,663 00 c. Testimony of company's engineer fixing present fair value for rate making purposes 900,000 00 d. Estimate by commissioner's engineer on basis of reproduction new, less depreciation at 1915 prices, plus additions since December 31, 1915, at actual cost, excluding Bluefield Valley waterworks, water rights, and going value 397,964 38 [262 U.S. 679, 685] e. Report of commission's statistician showing investment cost less depreciation 365,445 13 f. Commission's valuation, as fixed in case No. 368 ($360,000), plus gross additions to capital since made ($92,520.53) 452,520 53

It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to 'a,' supra: The commission deducted $204,000 from the estimate (details printed in the margin),1 leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see 'd,' supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10, 000 for working capital. If these be added to $421,000, there results $500, 600. This may be compared with the commission's final figure, $460,000. [262 U.S. 679, 686] As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

> 'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going val e, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10, 000 for working capital, producing $455,500.2 This may be compared with its final figure, $460,000.

As to 'f,' supra: It is necessary briefly to explain how this figure, $ 452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, [262 U.S. 679, 687] and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. 3 The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

> 'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of $324,427. ... From an examination of the books ... it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should [262 U.S. 679, 688] be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to e compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $ 452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:

> 'From the written opinion of the commission we find that it ascertained the value of the

> petitioner's property for rate making [then quoting the commission] 'after [262 U.S. 679, 689] maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record."

The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276 , 43 Sup. Ct. 544, 67 L. Ed . --, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U.S. 287, 289 , 40 S. Sup. Ct. 527, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):

> 'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00 . ... In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate [262 U.S. 679, 690] being regarded as justified by the risk incident to a hazardous investment.'
>
> 'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

> 'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U.S. 467, 547 , 18 S. Sup. Ct. 418, 434 (42 L. Ed. 819).
>
> 'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. ... And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U.S. 19, 41 , 52 S., 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).

> 'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U.S. 352, 434 , 33 S. Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18). [262 U.S. 679, 691] 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434.
>
> '... The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U.S. 454 , 33 Sup. Ct. 762, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:

> 'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. ... It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.' [262 U.S. 679, 692] It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth \$900,000. The final figure, \$460,000, was arrived at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and \$10, 000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sust ined. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately \$37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on \$460,000, amounting to \$27,600 for return. This was approved by the state court.

The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, 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 [262 U.S. 679, 693] 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. 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.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U.S. 19 , 48-50, 29 Sup. Ct. 192, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U.S. 655, 670 , 32 S. Sup. Ct. 389, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U.S. 153, 172 , 35 S. Sup. Ct. 811, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U.S. 256, 268 , 39 S. Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. [262 U.S. 679, 694] on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:

> 'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. 4

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent ., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In [262 U.S. 679, 695] this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.

Footnotes

[Footnote 1]

Difference in depreciation allowed $ 49,000 Preliminary organization and development cost 14,500 Bluefield Valley waterworks plant 25,000 Water rights 50,000 Excess overhead costs 39,000 Paving over mains 28,500 ___ $204,000

[Footnote 2] As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

[Footnote 3] Company City Engineer. Engineer.

[Footnote 1] Preliminary costs $14,455 $1,000

[Footnote 2] Water rights 50,000 Nothing

[Footnote 3] Cutting pavements over mains 27,744 233

[Footnote 4] Pipe lines from gravity springs 22,072 15,442

[Footnote 5] Laying cast iron street mains 19,252 15,212

[Footnote 6] Reproducing Ada springs 18,558 13,027

[Footnote 7] Superintendence and engineering 20,515 13,621

[Footnote 8] General contingent cost 16,415 5,448 ___ ___ 189,011 $63,983

[Footnote 4] This case was affirmed by this court June 4, 1923, 262 U.S. 443 , 43 Sup. Ct. 606, 67 L.

Ed. --.

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U.S. Supreme Court

FEDERAL POWER COM'N v. HOPE NATURAL GAS CO., 320 U.S. 591 (1944)

320 U.S. 591

FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.

CITY OF CLEVELAND
v.
SAME.

Nos. 34 and 35.
Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

[320 U.S. 591, 592] Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.

[320 U.S. 591, 593] Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.

Mr. William B. Cockley, of Cleveland, Ohio, for respondent.

Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. 717 et seq., 15 U.S.C.A . 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to 19(b) of the Act, the [320 U.S. 591, 594] Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F. 2d 287. The cases are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735 , 63 S.Ct. 1165

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. 1 It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. 2 In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the

Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March [320 U.S. 591, 595] 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609, 857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. 3 In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U. R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830, 892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required [320 U.S. 591, 596] to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of [320 U.S. 591, 597] reproduction cost new. On that basis Hope contended for a rate base of $66, 000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell Telephone Co., 292 U.S. 151 , 167-169, 54 S.Ct. 658, 664-666; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592 , 593 S., 62 S.Ct. 736, 745, 746, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve'4 of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. 5 The majority of the [320 U.S. 591, 598] Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $ 22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. 6

Hope's estimate of original cost was about $69,735,000-approximately $ 17,000,000 more than the amount found by the Commission. The item of $17, 000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended [320 U.S. 591, 599] in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. 7 The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $ 1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $ 3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the [320 U.S. 591, 600] property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust ... unlawful, or are not the lowest reasonable rates.' And Congress has provided in 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the [320 U.S. 591, 601] details of the general prescription8 of 4(a) and 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113 , 134. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135 , 155-157, 41 S.Ct. 458, 459, 460, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502 , 523-539, 54 S. Ct. 505, 509-517, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. 9 [320 U.S. 591, 602] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304 , 305 S., 314, 53 S.Ct. 637, 643, 644, 647; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70 , 55 S.Ct. 316, 320; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692 , 693 S., 55 S.Ct. 894, 906, 907 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414 , 29 S.Ct. 357; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401 , 58 S.Ct. 334, 341. [320 U.S. 591, 603] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. 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. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345 , 346 S., 12 S.Ct. 400, 402. 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. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291 , 43 S.Ct. 544, 547, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). 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.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by [320 U.S. 591, 604] the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $ 97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700, 000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P. U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all require- [320 U.S. 591, 605] ments, 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so- called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312 , 54

S.Ct. 647, 657. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to [320 U.S. 591, 606] the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U. S. at page 593, 62 S.C. at page 746. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. 10 By such a procedure the utility is made whole and the integrity of its investment maintained. 11 No more is required. 12 We cannot approve the contrary holding [320 U.S. 591, 607] of United Railways & Electric Co. v. West, 280 U.S. 234, 253 , 254 S., 50 S.Ct. 123, 126, 127. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. 13 Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate [320 U.S. 591, 608] commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. 14 Secondly, it is pointed out that West Virginia has a production tax15 on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. [320 U.S. 591, 609] Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. 16

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506 , 62 S.Ct. 384, 387, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as State of Missouri v. [320 U.S. 591, 610] Kansas Natural Gas Co., 265 U.S. 298 , 44 S.Ct. 544, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 , 47 S.Ct. 294, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' 1(b).

The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. 17 State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. 18 These were the types of problems with which those participating in the hearings were pre- occupied. 19 Congress addressed itself to those specific evils. [320 U.S. 591, 611] The Federal Power Commission was given broad powers of regulation. The fixing of 'just and reasonable' rates (4) with the powers attendant thereto20 was the heart of the new regulatory system. Moreover, the Commission was given certain authority by 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By 7(b) it was given control over the abandonment of facilities or of service. And by 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, 7(c) was broadened so as to require certifi- [320 U.S. 591, 612] cates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions21 contained in 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over- [320 U.S. 591, 613] 'the production or gathering of natural gas.' 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. 22 The Commission was also directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. 23 But it left the protection of [320 U.S. 591, 614] those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry24 or to protect the interests of those who sell their gas to the interstate operator. 25 The return which the Com- [320 U.S. 591, 615] mission allowed was the net return after all such charges.

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. 26 No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. 4.

But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users27 and domestic consumers. We hardly [320 U.S. 591, 616] can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. 28 But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that 4(a) and 5(a) contain only the conventional standards of rate-making for natural gas companies. 29 The [320 U.S. 591, 617] Act of February 7, 1942, by broadening 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. 30 But 4(a) and 5(a) were not changed. If the standard of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain . 5(a). The Commission, however, made no findings under 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not [320 U.S. 591, 618] for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. 31 However that may be, we do not think that these findings were reviewable under 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, [320 U.S. 591, 619] 1913, 28 U.S.C. 45, 47a, 28 U.S.C.A. 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125 , 59 S.Ct. 754. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' Id., 307 U.S. at page 130, 59 S.Ct. at page 757. And see United States v. Los Angeles & S. L.R. Co., 273 U.S. 299, 309 , 310 S., 47 S.Ct. 413, 414, 415; Shannahan v. United States, 303 U.S. 596 , 58 S.Ct. 732. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

REVERSED.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418 , 10 S.Ct. 462, 702), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning [320 U.S. 591, 620] of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575 , 599-601, 62 S.Ct. 736, 749, 750.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350 , 37 S.Ct. 298, 302, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just [320 U.S. 591, 621] and reasonable.' 1 Section 62 throws additional light on the meaning of these words.

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418 , 461-466, 10 S.Ct. 462, 702, 703-705, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the en- [320 U.S. 591, 622] actment of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287 , 304 et seq., 53 S.Ct. 637, 643 et seq.. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371 , 63 S. Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644. Historical cost, prudent investment and reproduction cost3 were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. 4 The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates. [320 U.S. 591, 623] I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate [320 U.S. 591, 624] making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.

My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as [320 U.S. 591, 625] the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331 , 6 S.Ct. 334, 344, 388, 1191, it was decided more than fifty years ago that the final say under the

Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418 , 10 S.Ct. 462, 702.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. 5 of the Natural Gas Act, 15 U.S. C. 717d, 15 U.S.C.A. 717d. Instead of making the Commission's rate determinations final, Con- [320 U.S. 591, 626] gress specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', 19 of the Act, 15 U.S.C. 717r; 15 U.S.C.A. 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for [320 U.S. 591, 627] instance, 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466 , 18 S.Ct. 418, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104 , 59 S.Ct. 715. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided [320 U.S. 591, 628] in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co.1 But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. 2 I disclaim this im- [320 U.S. 591, 629] puted approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. 3

Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is [320 U.S. 591, 630] available only to about 7,600,000 consumers. 4 Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $ 16 per barrel. 5 The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. 6 Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000.7 Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

While for many years natural gas had been distributed on a small scale for lighting,8 its acceptance was slow, [320 U.S. 591, 631] facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. 9 Soon monopoly of production or markets developed. 10 To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. 11 The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. 12 [320 U.S. 591, 632] With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917.13

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. 14 West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunc- [320 U.S. 591, 633] tion from this Court. 15 Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. 16 That Commission held that a company could not abandon a part of its territory and still serve the rest. 17 Some courts admonished the companies to take action to protect consumers. 18 Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. 19 There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. 20 Public service commissions of consuming states were handicapped, for they had no control of the supply. 21 [320 U.S. 591, 634] Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. 22 After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. 23

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water [320 U.S. 591, 635] heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. 24 But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. 25

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on in- [320 U.S. 591, 636] dustrial, 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7.26 Although this spread is less than in other parts of the United States,27 it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. 28 [320 U.S. 591, 637] These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. 29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. 30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate [320 U.S. 591, 638] subsidiaries,31 the effect of which, if not the purpose, was to isolate some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' 32 Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' 33 While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity [320 U.S. 591, 639] permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' 34 The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,'35 which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates ... either as between localities or as between classes of service.' 36 And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' 37

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. 38 I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.' [320 U.S. 591, 640] III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery. As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries. [320 U.S. 591, 641] Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to [320 U.S. 591, 642] time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).'39

The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it con- [320 U.S. 591, 643] tained the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, 312 (c). Congress rejected this language. See H.R. 5423, 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. 40 Of [320 U.S. 591, 644] course, the Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors. [320 U.S. 591, 645] The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise, [320 U.S. 591, 646] I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not '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.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. 41

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation,42 and the purposeful and deliberate innovation I [320 U.S. 591, 647] would make to meet the necessities of regulating the industry before us.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue [320 U.S. 591, 648] in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute,43 is not even urged by the gas company for valuing its fields. [320 U.S. 591, 649] The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West

Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and [320 U.S. 591, 650] adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621 , 43 S.Ct. 658, 674, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405 , 37 S.Ct. 156, 157, Ann. Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property ... at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to [320 U.S. 591, 651] regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236 , 39 S.Ct. 268; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23 , 40 S.Ct. 279. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300 , 49 S.Ct. 150; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322 , 49 S.Ct. 157. Then, as now, the differences were 'due chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311 , 49 S.Ct. 150, 153. No one seems to have questioned that the rate base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290 , 54 S.Ct. 647; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398 , 54 S.Ct. 763, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point [320 U.S. 591, 652] if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform [320 U.S. 591, 653] for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine ....' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the [320 U.S. 591, 654] field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio.44 What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas?45 Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has [320 U.S. 591, 655] if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, Block v. Hirsh, 256 U.S. 135 , 41 S.Ct. 458, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170 , 41 S.Ct. 465; International Harvester Co. v. Kentucky, 234 U.S. 216 , 34 S.Ct. 853; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253 , 49 S.Ct. 314, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657 , 61 S.Ct. 451, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38 , 59 S.Ct. 648; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533 , 59 S.Ct. 993; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381 , 60 S.Ct. 907. The Commission has power to fix [320 U.S. 591, 656] a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. 46 The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606 , 62 S.Ct. 736, 753. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner [320 U.S. 591, 657] and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long- range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? 47 And how much cheaper should indus- [320 U.S. 591, 658] trial gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction [320 U.S. 591, 659] of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be [320 U.S. 591, 660] at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373 , 62 S.Ct. 717; United States v. Lowden, 308 U.S. 225 , 60 S.Ct. 248.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

Footnotes

[Footnote 1] Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

[Footnote 2] These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia sales 11,000,000 East Ohio 40,000,000 Peoples 10,000,000 River 400,000 Fayette 860,000 Manufacturers 2,000,000

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

[Footnote 3] These required minimum reductions of 7õ per m.c.f. from the 36.5õ and 35.5õ rates previously charged East Ohio and Peoples, respectively, and 3õ per m.c.f. from the 31.5õ rate previously charged Fayette and Manufacturers.

[Footnote 4] The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

[Footnote 5] That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424 , 425 S., 29 S.Ct. 357, 361, 362; 2 Bonbright, Valuation of Property (1937), p. 1139.

[Footnote 6] The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

[Footnote 7] See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

[Footnote 8] Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[Footnote 9] We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540 , 63 S.Ct. 727, 738.

[Footnote 10] Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

[Footnote 11] See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234 , 259-288, 50 S.Ct. 123, 128-138, for an extended analysis of the problem.

[Footnote 12] It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

[Footnote 13] See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

[Footnote 14] West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

[Footnote 15] W.Va.Rev.Code of 1943, ch. 11. Art. 13, 2a, 3a.

[Footnote 16] West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

[Footnote 17] S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

[Footnote 18] S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

[Footnote 19] See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

[Footnote 20] The power to investigate and ascertain the 'actual legitimate cost' of property (6), the requirement as to books and records (8), control over rates of depreciation (9), the requirements for periodic and special reports (10), the broad powers of investigation (14) are among the chief powers supporting the rate making function.

[Footnote 21] Apart from the grandfather clause contained in 7(c), there is the provision of 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

[Footnote 22] See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

[Footnote 23] As we have pointed out, 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.

The bill amending 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

[Footnote 24] We have noted that in the annual operating expenses of some $16, 000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

[Footnote 25] The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $ 1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

[Footnote 26] See note 25, supra.

[Footnote 27] The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

[Footnote 28] Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

[Footnote 29] The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404 , 405 S., 54 S.Ct. 763, 766, 767, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

[Footnote 30] The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[Footnote 31] The argument is that 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[Footnote 1] Natural Gas Act, 4(a), 52 Stat. 821, 822, 15 U.S.C. 717c(a), 15 U.S.C.A. 717c(a).

[Footnote 2] 52 Stat. 821, 824, 15 U.S.C. 717e, 15 U.S.C.A. 717e:

> '(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

[Footnote 3] 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

[Footnote 4] It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T . & T. Co. v. United States, 299 U.S. 232 , 57 S.Ct. 170. But the latter is the traditional method.

[Footnote 1] 315 U.S. 575 , 62 S.Ct. 736.

[Footnote 2] Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122 , 59 S.Ct. 715, 724, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

[Footnote 3] Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

[Footnote 4] Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

[Footnote 5] Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

[Footnote 6] Id. at 62-63.

[Footnote 7] Id. at 61.

[Footnote 8] At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

[Footnote 9] In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. 1981 et seq.

[Footnote 10] See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

[Footnote 11] Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

[Footnote 12] Id. at 63.

[Footnote 13] Id. at 64.

[Footnote 14] See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

[Footnote 15] Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553 , 43 S. Ct. 658, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

[Footnote 16] People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

[Footnote 17] Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

[Footnote 18] See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

[Footnote 19] People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

[Footnote 20] East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308 , 49 S.Ct. 150, 152.

[Footnote 21] The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce ..., Congress has not taken over the regulation of that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210, 212.

[Footnote 22] Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

[Footnote 23] For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

[Footnote 24] The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:

Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.

Natural gas at 2.00 per M. is equivalent to gasoline at 27õ per gal.

Natural gas at 2.20 per M. is equivalent to electricity at 3õ per k.w. h.

Natural gas at 2.40 per M. is equivalent to coal oil at 15õ per gal.

Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

[Footnote 25] See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

[Footnote 26] Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

[Footnote 27] From the source quoted in the preceding note the spread elsewhere is shown to be:

State Industrial Domestic Illinois 29.2 1.678 Louisiana 10.4 59.7 Oklahoma 11.2 41.5 Texas 13.1 59.7 Alabama 17.8 1.227 Georgia 22.9 1.043

[Footnote 28] In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70õ for the first 5,000 cu. ft. per month; 80õ from 5, 000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58õ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.

The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35õ; second 5,000 feet, 45õ; third 5,000 feet, 50õ; all above 15,000, 55õ. This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75õ; next 4 m.c.f., 60õ; next 8 m.c.f., 55õ; over 15 m.c.f., 50õ. Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.

For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas

Association of America (1919) 287.

[Footnote 29] See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

[Footnote 30] Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.

In 1915, so it was reported to the Governor of West Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

[Footnote 31] This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300 , 49 S.Ct. 150; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322 , 49 S.Ct. 157; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290 , 54 S.Ct. 647; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398 , 54 S.Ct. 763, 91 A.L.R. 1403, and the present case.

[Footnote 32] 15 U.S.C. 717(a), 15 U.S.C.A. 717(a). (Italics supplied throughout this paragraph.)

[Footnote 33] 7(c), 52 Stat. 825, 15 U.S.C.A. 717f(c).

[Footnote 34] 15 U.S.C. 717f, 15 U.S.C.A. 717f.

[Footnote 35] Id., 717c(e).

[Footnote 36] Id., 717c(b).

[Footnote 37] Id., 717d(a).

[Footnote 38] Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

[Footnote 39] The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

[Footnote 40] To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. ... Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high.

It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.'As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. ... Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. ... But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. ... A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

[Footnote 41] See 2 Bonbright, Valuation of Property (1937) 1112.

[Footnote 42] Bonbright says, '... the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

[Footnote 43] 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

[Footnote 44] East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

[Footnote 45] Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

[Footnote 46] I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

[Footnote 47] The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.

> 'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

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Mignault J.

The petition is therefore dismissed with costs.

Petition dismissed with costs.

Solicitors for the petitioner: *Griffin, Montgomery & Smith.*

Solicitor for the respondent: *R. W. Ginn.*

1928
*Oct. 24.
1929
*Feb. 5.

NORTHWESTERN UTILITIES, LIMITED .... APPELLANT;

AND

THE CITY OF EDMONTON AND BOARD OF PUBLIC UTILITY COMMISSIONERS OF ALBERTA .... RESPONDENTS.

THE CITY OF EDMONTON .... APPELLANT;

AND

NORTHWESTERN UTILITIES, LIMITED, AND BOARD OF PUBLIC UTILITY COMMISSIONERS OF ALBERTA .... RESPONDENTS.

ON APPEAL FROM THE APPELLATE DIVISION OF THE SUPREME COURT OF ALBERTA

Public utilities—Public Utilities Act, Alta.—Hearings and investigations by Board of Public Utility Commissioners—Powers of Board—Obtaining of evidence—Absence of evidence—Order of Board fixing rates for gas supply in municipality by franchise holder—Return on investment—Inclusion in "rate base" of discount on sale of bonds—Appeal from Board's order—"Question of law."

The Board of Public Utility Commissioners of Alberta made an order in 1922 fixing rates chargeable for gas proposed to be supplied in the city of Edmonton by the predecessor of the appellant company. The Board fixed the rates on the basis of an allowance of 10% as a fair return on the investment in the enterprise, and in determining the "rate base" (the amount to be considered as invested in the enterprise) it included as a capital expenditure a sum which was the discount on the sale of the company's bonds. The rates were to continue in force for three years from the date on which gas was first

*PRESENT:—Anglin C.J.C. and Mignault, Rinfret, Lamont and Smith JJ.

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supplied. In 1926 the appellant company applied for continuation of the rates. On this application the city objected to such a high rate of return and to the inclusion in the rate base of the item for bond discount. The Board continued said item in the rate base, but reduced the return to 9% "in view of the elements which go to make up the rate base, and in view of the altered conditions of the money market." The parties appealed (by leave) to the Appellate Division, Alta., and then to this Court, the company against the reduction of the rate of return, and the city against the inclusion of the bond discount item in the rate base. The company contended that no evidence was adduced before the Board of "altered conditions of the money market," and that, without hearing evidence upon the point and giving the company opportunity to establish that the conditions of the money market had remained unaltered since 1922, the Board acted without jurisdiction in making the reduction. Under s. 47 of *The Public Utilities Act, 1923*, Alta., c. 53, as amended 1927, c. 39, an appeal lies from the Board upon a question "of jurisdiction" or "of law," upon leave obtained.

Held 1. The company's last mentioned contention involved a "question of law," and therefore it had a right to appeal.

2. The city's appeal failed; the question raised thereon was not one of jurisdiction or law.

3. The company's appeal failed. The Board had power to reduce the rate of return, notwithstanding that at the hearing before it no witnesses testified as to altered conditions of the money market. The company's contention that to alter the rate of return would be unfair to its shareholders who had invested in the enterprise after the order fixing the rates in 1922, was not a matter open for consideration upon the appeal, as it did not involve a question of jurisdiction or law.

Per Rinfret and Lamont JJ.: A consideration of ss. 21 (4) (5), 25, 43, and 44 of the said Act, the purposes of the Act, and the extent of the powers vested in the Board, leads to the conclusion that the intention of the legislature was to leave it largely to the Board's discretion to say in what manner it should obtain the information required for the proper exercise of its functions; it was not to be bound by the technical rules of legal evidence, but was to be governed by such rules as, in its discretion, it thought fit to adopt. An inference that it had not the proper evidence before it as to the altered conditions of the money market could not be drawn from the fact that no oral testimony in respect thereof was given at the hearing. The company had notice that a reduction was sought and that the city was attacking the methods and principles adopted in fixing the rate of return in 1922. This put the whole question of a fair return at large and informed the company that it would have to establish to the Board's satisfaction every element and condition necessary to justify a continuation of the 10% rate; and there was nothing in the record to justify the conclusion that the company had not the opportunity of making proof at the hearing as to the conditions of the money market.

Per Smith J.: The Board has power to reduce the rate of return without evidence; the question of a fair rate of return is largely one of opinion, hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.

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APPEALS by Northwestern Utilities, Limited, and the City of Edmonton, respectively, from the dismissal by the Appellate Division of the Supreme Court of Alberta of their respective appeals from the award of the Board of Public Utility Commissioners for the Province of Alberta fixing rates to be paid by consumers of natural gas, for the supply of which within the city of Edmonton the said company, Northwestern Utilities, Limited, has a franchise.

The company applied to the Board for an order continuing the rates which had been fixed for a certain period by an order of the Board made in 1922. The Board made an award fixing the rates, from which each party appealed to the Appellate Division. Under s. 47 of *The Public Utilities Act* of Alberta, 1923, c. 53, as amended 1927, c. 39, an appeal lies from the Board to the Appellate Division "upon a question of jurisdiction or upon a question of law," if leave to appeal is obtained as therein provided. Such leave to appeal was obtained, it being reserved to each party to move before the Appellate Division to set aside the order granting leave to the other party, on the ground that the matters as to which leave to appeal was given did not involve any question of law or jurisdiction.

The company's objection to the Board's award was that it fixed the rates on the basis of an allowance of only 9%, instead of 10% which was allowed under the order made in 1922, as the "rate of return" on the investment in the enterprise. The Board in its award said:—

> In view of the elements which go to make up the rate base, and in view of the altered conditions of the money market, the Board believes it is justified in reducing the rate of return that the company shall be allowed, to nine per cent., and the Board's estimates are on that basis.

The company contended that there was before the Board no evidence of any "altered conditions of the money market," that the "elements which go to make up the rate base" were the same as in 1922, and afforded no reason for changing the rate of return, that to reduce the rate of return would be unfair to its shareholders, who had invested in the enterprise after the order fixing the rates in 1922, that the money was invested and the plant constructed on the strength of the principles laid down in the 1922 award, and that it was clearly understood that the principles then adopted would govern all future revisions.

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The city's objection to the award was that, in determining the "rate base" (the amount to be considered as invested in the enterprise) it included (as it had done in the 1922 award) as a capital expenditure a sum which was the discount on the sale of the company's bonds.

The Appellate Division dismissed both appeals (no written reasons being given). Subsequently it made separate orders giving each party leave to appeal to the Supreme Court of Canada. On an application by both parties in the Supreme Court of Canada, the appeals were consolidated.

By the judgment of this Court both appeals were dismissed with costs.

E. Lafleur K.C. and *H. R. Milner K.C.* for Northwestern Utilities, Limited.

O. M. Biggar K.C. for the City of Edmonton.

The judgment of Anglin C.J.C. and Mignault J., was delivered by

ANGLIN C.J.C.—While, with my brother Smith, I incline to the view that the appellant company may have some reason to complain of unfairness in the judgment of the Board of Public Utility Commissioners reducing the rate of return from 10% to 9%, I agree with the conclusion reached by my brother Lamont and concurred in by my brother Smith that it is not open to us to entertain the appeal of the company on that ground. It does not seem to raise either a question of law or jurisdiction within the purview of the statute on which the right of appeal rests. I would dismiss the appeal.

The judgment of Rinfret and Lamont JJ. was delivered by

LAMONT J.—These are separate but consolidated appeals by the Northwestern Utilities, Limited (hereinafter called the Company) and the City of Edmonton, respectively, from the dismissal by the Appellate Division of the Supreme Court of Alberta of their respective appeals against the award made by the Board of Public Utility Commissioners on an application by the company for an

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order fixing the price to be paid by the consumers of natural gas within the city. Subsequent to the dismissal of the appeals, the Appellate Division made separate orders giving each party leave to appeal to this Court. By a further order the appeals were consolidated.

The company is the successor of the Northern Alberta Natural Gas Development Company, which held a franchise from the city for the supply of natural gas to the inhabitants thereof.

Disputes having arisen between the Development Company and the city, and an action having been commenced, the parties, on August 28, 1922, agreed to a settlement of their difficulties. One of the terms of the settlement was that the prices or rates to be paid by the inhabitants of the city should be fixed by the Board of Public Utility Commissioners. An application was accordingly made to the Board, the parties were heard, and, on November 27, 1922, an order was made fixing the rates to be paid. These rates were to continue in force for three years from the date on which gas was first supplied to consumers.

In order to fix just and reasonable rates, which it was the duty of the Board to fix, the Board had to consider certain elements which must always be taken into account in fixing a rate which is fair and reasonable to the consumer and to the company. One of these is the rate base, by which is meant the amount which the Board considers the owner of the utility has invested in the enterprise and on which he is entitled to a fair return. Another is the percentage to be allowed as a fair return.

In the award of 1922, which came into operation in the fall of 1923, the Board included in the rate base as a capital expenditure the sum of $283,900 (10% of the cost of plant) as, "an allowance for the promotion and financing" of the company, and the sum of $650,000 which was the discount on the sale of the Development Company's bonds. It also determined that 10% was a fair return on the investment. The rates thus fixed by the Board, with certain alterations made with the consent of all parties, continued in force for three years. In October, 1926, the appellant company, which had succeeded to the rights of the Development Company, applied to the Board for an order continuing the rates for such period as the Board might see fit. In its

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reply to the application the city submitted (par. 23) that the order of November, 1922, should in certain respects be disregarded. One of these was the following:—

(e) Rate of Return. It is submitted that the methods and principles adopted in the fixing of the rate of return are erroneous and that the rate of return allowed is too high.

The city also protested against including in the rate base the item for the promotion and financing of the company and the item for bond discount.

In its answer to the city's reply the company alleged (par. 10) that at the hearing in 1922 the city was fully and adequately represented, that it had submitted evidence, that upon the award being delivered it raised no objection to any part thereof, and, therefore, was now estopped from contending that the principles then laid down were wrong in principle or in fact.

In its award the Board continued both the above mentioned sums in the rate base, but reduced the rate of return to the company from 10% to 9%. The reason assigned by the Board for this reduction is as follows:—

In view of the elements which go to make up the rate base, and in view of the altered conditions of the money market, the Board believes it is justified in reducing the rate of return that the Company shall be allowed, to nine per cent., and the Board's estimates are on that basis.

From the award the parties appealed, first to the Appellate Division of the Supreme Court of Alberta, and now to this Court. The company appealed against the reduction of the rate of return on its capital expenditure to 9%. Referring to the reasons given by the Board for making the reduction the company in its factum says:—

1. The city adduced no evidence as to "altered conditions of the money market" and

2. "The elements which go to make up the rate base" in 1927 are the same as in 1922.

The city appealed against the inclusion in the rate base of the item of the bond discount above mentioned.

The *Public Utilities Act* allows an appeal from the Board only upon a question of jurisdiction, or upon a question of law, and even then only when leave to appeal has first been obtained from a judge of the Appellate Division.

As against the company's appeal the city raises the preliminary objection that no question either of jurisdiction or law is involved therein. In my opinion the objection cannot be sustained. The substance of the company's appeal is that the Board in making a reduction in the rate of return did so for two reasons, one of which was the "altered conditions of the money market," and that of this no evidence was adduced before the Board. The company contends that, without hearing evidence upon the point, and without giving it an opportunity to establish that the conditions of the money market had remained unaltered since 1922, the Board was without jurisdiction to make the reduction. This contention was not stated in this form in the order granting leave to appeal to the Appellate Division, but the fixing of the rate of return at 9% only, was there set out as an error of the Board in respect of which leave to appeal was granted.

Whether or not the Board can properly base an order (in part at least) on the existence of a state of fact of which no evidence was adduced before it at the hearing and as to which the party affected has not had any opportunity of being heard is, in my opinion, a question of law which depends for its answer upon the construction to be placed upon the *Public Utilities Act.*

I am, therefore, of opinion that the company had a right to appeal.

The question involved in this appeal is: Had the Board jurisdiction to find as a fact how the conditions of the money market had altered between November, 1922, and July, 1927, without any witness testifying at the hearing that an alteration had taken place.

As the Board was determining what would be a fair return on the capital invested by the company in the enterprise, and as it reduced the return from 10% to 9%, it can, I think, be taken that by "the altered conditions of the money market" the Board meant that the returns for money invested in securities in which moneys were ordinarily invested had decreased during the period in question. In other words, that the rate of interest obtainable for moneys furnished for investment was, generally speaking, lower by a certain percentage in 1927 than it was in 1922. That, in my opinion, is all that is involved in the finding.

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 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.

For the city it was argued that, as one of the statutory powers of the Board was to deal with the financial affairs of local authorities (s. 20 (*d*)), and as this included the power to authorize the issue of new debentures by these authorities and to determine the rate of interest to be paid thereon and also the power to order a variation of the rate of interest payable upon any debt of the local authority (s. 103), the Board must necessarily be familiar with the rate of interest prevailing from time to time and therefore did not require to have witnesses called to furnish it with information which in the regular performance of its duty it was obliged to possess. In view of the powers and duties of the Board under the Act there is, in my opinion, considerable to be said for the city's contention. It is not necessary, however, to determine this question, for in the statute itself I find sufficient to justify the conclusion that the intention of the Legislature was to leave it largely to the discretion of the Board to say in what manner it should obtain the information required for the proper exercise of its functions.

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The material provisions of the Act on this point are as follows:—

21. (4) The Board may in its discretion accept and act upon evidence by affidavit or written affirmation or by the report of any officer or engineer appointed by it or obtained in such other manner as it may decide.

(5) All hearings and investigations before the Board shall be governed by rules adopted by the Board, and in the conduct thereof the Board shall not be bound by the technical rules of legal evidence.

Section 25 provides that upon a complaint being made to the Board that any proprietor of a public utility has unlawfully done or unlawfully failed to do something relating to a matter over which the Board has jurisdiction, the Board shall "after hearing such evidence as it may think fit to require" make such order as it thinks fit under the circumstances. Section 43 provides that the Board may "appoint or direct any person to make an inquiry and report upon any application * * * before the Board." And by section 44 the Board may "review, rescind, change, alter or vary any decision or order made by it." A perusal of these statutory provisions and a consideration of the purposes of the Act and the extent of the powers vested in the Board leads me to the conclusion that the Legislature intended to create a Board which in the exercise of its functions should not be bound by the technical rules of legal evidence but which would be governed by such rules as, in its discretion, it thought fit to adopt (s. 21 (5)). We have not been made acquainted with the rules, if any, adopted by the Board to govern its investigations. Nor do we know what information it possessed as to the altered conditions of the money market; but, as it had authority to act on evidence "obtained in such manner as it may decide" (s. 21 (4)), an inference that it had not the proper evidence before it cannot be drawn from the fact that no oral testimony in respect thereof was given at the hearing. If, in this case, the Board had asked its secretary to inquire from the various financial institutions in Edmonton if there had been any alteration in the conditions of the money market between 1922 and 1927, and the secretary had reported that there had been a certain decrease in the returns from invested capital, would it have been necessary to call witnesses to verify the report? In my opinion it would not. Nor would it have been necessary to afford to either party an opportunity to controvert before the

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Board the information so obtained. Then would it have been necessary to mention in the award that the fact that such altered conditions had been established to the satisfaction of the Board by a report of its secretary? I can find nothing in the Act requiring mention to be made of the evidence or of the manner of obtaining it.

Reference was made to s. 86, which provides that no order involving any outlay, loss or depreciation to the proprietor of any public utility or to any municipality or person shall be made without due notice and full opportunity to all parties concerned to make proof to be heard at a public sitting of the Board, except in the case of urgency. A reduction in the rate of return to the company would, in my opinion, come within this section. The Board was, therefore, without jurisdiction to make the reduction unless the company had notice that a reduction was sought and had an opportunity of proving that under the circumstances existing at the time of the hearing the existing rate of return was fair and reasonable. That the company had notice that the city was demanding a reduction is beyond question (par. 23 (*e*)). It had more. It had notice that the city was attacking the methods and principles adopted in fixing the rate of return in 1922. This, in my opinion, put the whole question of a fair return at large and informed the company that it would have to establish to the satisfaction of the Board every element and condition necessary to justify a continuation of the 10% rate. The company does not say that it was refused an opportunity of putting in evidence as to the conditions of the money market. Nowhere does it deny that it could have put in evidence had it so desired. What it does say is that the city did not adduce evidence on the point and that no witnesses were called to testify before the Board in regard thereto. There is nothing before us to justify an inference that the company was not at liberty to call witnesses as to the conditions of the money market had it so desired. Moreover, in the order which the company obtained giving it leave to appeal it did not even suggest that it had no opportunity of submitting evidence as to the existing market conditions. The ground upon which the company relied to meet the city's demand for a reduction, as set out in the answer which it filed, was that as the city had ac-

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cepted the award when it was delivered and had raised no objection thereto, it was now precluded from seeking to set aside the principles upon which the rate of return was based. In its factum it went further and contended that, even if there was no estoppel, the principles then adopted should now be adhered to because it was on the strength of their having been adopted that the shareholders of the company invested their money in the enterprise. This contention cannot be made effective. In the first place, it involves neither a question of jurisdiction nor of law. In the second place, it is the duty of the Board to fix rates which, in its opinion, will be fair and reasonable at the time the order is made and for the period for which they are fixed. If any wrong principle or erroneous view has been adopted it is the duty of the Board at the next revision to correct the error. The argument that it would be unfair to the shareholders now to alter the rate of return is not a matter open for consideration on appeal. Moreover, when these shareholders invested their money they knew that the rates fixed were to be in force for three years only and that it would be the duty of the Board on the next revision to fix rates which at that time would be fair and reasonable under the circumstances then existing.

Our attention was also called to s. 47 (1a) as indicating an intention that evidence must be taken on all material points. That subsection reads as follows:—

(1a) On the hearing of any appeal referred to in subsection 1 of this section no evidence other than the evidence which was submitted to the Board upon the making of the order appealed from shall be admitted, and the Court shall proceed either to confirm or vacate the order appealed from, and in the latter event shall refer the matter back to the Board for further consideration and redetermination.

In my opinion this subsection means no more than that no new evidence is to be admitted on appeal.

The appeal of the company should therefore be dismissed with costs.

The appeal of the city should likewise be dismissed with costs. The items which should be included in the rate base cannot, in my opinion, be considered a question of jurisdiction or of law.

SMITH J.—The City of Edmonton had made an agreement with the Northern Alberta Natural Gas Development Company, by which the company obtained a fran-

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chise to supply natural gas to the city, and agreed to construct the necessary works. The company failed to construct the works, and the city sued for damages for breach of contract. The actions were settled by an agreement dated 22nd August, 1922, under which the determination of the rates to be charged by the company for gas was referred to the Board of Public Utility Commissioners, and the company was, within six months after the fixing of the rates, to deposit $50,000 with the city, which was to be forfeited to the city as liquidated damages in case the company did not complete the construction of the works as agreed.

A rate hearing was held by the Board after this settlement, at which the company and the city were represented, and the Board made an award, setting out a rate basis and fixing prices for gas on this basis.

The difficulty about proceeding with the works had been the procuring of capital on the basis of prices provided in the original agreement and amendments made. The whole object of fixing a rate base and prices in advance of construction was to facilitate financing by the company. It would necessarily be on the basis of the award that investors would buy bonds and stock of the company. The company had the option of proceeding with the works or abandoning them and forfeiting the $50,000, after seeing the award. In July following the making of the award, the company assigned its franchise and property to the appellant, the Northwestern Utilities, Limited, which, by sale of its bonds and stock, raised the necessary capital, constructed the works, and put them in operation. The rate to be charged for gas was fixed by the award for three years, and at the end of this period the company applied to the Board for continuation of the rates fixed by the award. The rate base fixed by the Board in the award of 1922 contained many items, such as total investment, operating cost, depletion reserve, reserve for repayment of cost of plant, total necessary revenue, amounts of gas to be sold, and the rate of return on capital to be allowed. It is evident that, with the exception of the last of these items, the amounts fixed must have been estimates, liable to be varied by actual results.

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The rate of return to be allowed on capital was fixed in the award at 10%, not based on the ordinary rate of money on the market at the time or on an estimated future rate, but on consideration of the rate that would induce investors to risk their capital in an extremely hazardous and doubtful venture. At the hearing before the Board in 1922, the company had asked a 12% rate of return on capital, and the city had conceded 10%, which the Board fixed, though it stated that under the circumstances a return of more than 10% would not seem to be unjust. The reason set out for not fixing this higher rate was that it might so restrict the market that the higher rate would not compensate for the restriction of the market, and would therefore not be to the advantage of the company. It is, however, stated that in case of future revision, it may be found desirable, under certain circumstances, to increase this rate.

On the revision at the end of three years, this rate was not increased, but was reduced from 10% to 9%, at the instance of the city, and this reduction constitutes the ground of appeal.

In the reasons given by the Board in fixing the new rates, it is pointed out that, where rates have been fixed in advance of construction and financing, the Board is not precluded from subsequently making changes that may appear from subsequent reconsideration to be necessary, and it is then stated that

> those investing in such a case must depend on the fairness of the Board in seeing that the Company is allowed a fair and reasonable return upon its investment, but the Board may, and indeed it should, take into consideration the circumstances under which such investment was made.

In discussing these circumstances in reference to a request by the city for elimination from the rate base of the 1922 award of the item for bond discount, the Board says:

> There is, moreover, an additional factor to be considered in the present case and that is, that in 1922 the inclusion of the allowance for bond discount was practically agreed to by the city in its case and the item was not questioned by the city until at the recent hearing. It is only fair to assume that the fact of the inclusion of the bond discount in the rate base formed part of the inducement for the making of the investment. Under the circumstances, therefore, the Board does not feel justified in adopting the City's contention in this regard.

This lays down a principle with which one heartily agrees, and which applies exactly to the city's application for reduction of the rate of return on capital fixed in the award

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of 1922 at 10%. The Board fixed this rate with the assent of the city, and this rate, coupled with the suggestion by the Board that it might be increased, "formed part of the inducement for the making of the investment."

The altered condition of the money market, given as a reason for the reduction of the rate to 9%, seems to me to have no bearing on the matter. The representation to the investor in 1922 was, for the risk you take in placing your capital in a hazardous undertaking, you will be allowed as a basis in fixing rates to be charged for gas a return of 10%. What the regular money market might be three years later could have nothing to do with the decision to invest. The whole question was, viewing the risk, and the chances, as matters then stood, was the chance of 10% on the money worth the risk of a bad investment, with the possibility of the loss of all or part of the capital?

The Board then, in my opinion, laid down a proper principle, and applied it in other instances, but failed to apply it to this item, as to which I think it was particularly applicable. The question is, can this Court set aside the finding of the Board as to this item on the appeal? I agree with my brother Lamont that, whether or not under the Act the Board was entitled to reduce the rate to 9% without evidence, because of a change in money market conditions, is a question of law, and that there is therefore a right of appeal, and it is with some regret that I feel bound to agree with him that the Board had jurisdiction to make the change in rate without evidence, and without giving the company an opportunity to offer evidence. The question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.

I am not entirely in accord with the observations of my brother Lamont in reference to the sending out of someone to gather evidence of the state of the money market and acting on that party's report without the knowledge of the company. The objection in such a case would not be the failure to set out in the award the fact of such evidence and its nature, but the failure to disclose it to the company with an opportunity to answer it. If it were a case where, evi-

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dence being necessary, it had been taken in the manner suggested, or otherwise, and a finding based on it without disclosure of it to the company and an opportunity to answer it, I would regard such a proceeding as contrary to elementary principles of justice, and as affording, under the statute, a ground for setting the award as to this item aside and referring it back for reconsideration. It does not, however, appear that any evidence was taken, and as stated, I have concluded that there was power to make the change without evidence.

I therefore concur with my brother Lamont in the disposal of this appeal.

Appeals dismissed with costs.

Solicitors for Northwestern Utilities, Limited: *Milner, Carr, Dafoe & Poirier.*

Solicitor for the City of Edmonton: *John C. F. Bown.*

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*Oct. 2, 3, 4, 5, 6, 8, 9, 10, 11, 12, 15.

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*Feb. 5.

IN THE MATTER OF A REFERENCE AS TO THE RELATIVE RIGHTS OF THE DOMINION AND PROVINCES IN RELATION TO THE PROPRIETARY INTEREST IN AND LEGISLATIVE CONTROL OVER WATERS WITH RESPECT TO NAVIGATION AND WATER-POWERS CREATED OR MADE AVAILABLE BY OR IN CONNECTION WITH WORKS FOR THE IMPROVEMENT OF NAVIGATION.

Constitutional law—Water-powers—Navigable river—Public right of navigation—Right of the Dominion as to the use of the bed of a river and as to expropriation of provincial property—Relative rights of the Dominion and provinces over water-power created by works done by the Dominion—Boundary waters—Interprovincial and provincial rivers—B.N.A. Act, ss. 91, 92, 108 to 126.

The questions referred to this court by the Governor General in Council were answered as follows: (1)

*PRESENT:—Anglin C.J.C. and Duff, Mignault, Newcombe, Rinfret, Lamont and Smith JJ.

(1) *Reporter's Note.*—In view of the difficulties which the court found in dealing with the questions before it and of the impossibility of giving precise and categorical answers, it was thought best in order to avoid misleading as to what was decided, to put as a head-note the text of the formal

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REFERENCE re WATERS AND WATER-POWERS.

Question 1 (a). Where the bed of a navigable river is vested in the Crown in the right of the province, is the title subordinate to the public right of navigation?

Question 1 (b). If not, has the Dominion the legislative power to declare that such title is subordinate to such right?

Answer: The questions as framed postulate the existence of a public right of navigation in the rivers to which they refer, as well as their navigability.

The title to the bed of the river is subject to that public right, except in so far as, at the date of the Union, the Crown possessed by law or has since acquired, under Dominion legislation, a superior right to use or to grant the use of the waters of the river for other purposes, such for example, as mining, irrigation or industry.

Question 2. Where the bed of a navigable river is vested in the Crown in the right of the province, has the Dominion power, for navigation purposes, to use or occupy part of such bed or to divert, diminish, or change the flow over such bed (a) without the consent of the province; (b) without compensation?

Question 3. Has the Parliament of Canada the power, by appropriate legislative enactment, to authorize the Dominion Government to expropriate the lands of the Crown in the right of the province for the purposes of navigation with provision or without provision for compensation?

Answer: These questions cannot be answered categorically either in the affirmative or in the negative.

The conditions controlling the exercise of Dominion legislative powers for purposes embraced within the comprehensive phrase, "navigation purposes," depend in part upon the nature of the "purpose," in part upon the nature of the means proposed for accomplishing it, and in part upon the character of the particular power called into play. Reference is respectfully made to the observations in the accompanying reasons, as indicating the governing principles with as much definiteness as is safe or practicable.

Question 4. By section 108 of the British North America Act, 1867, and the first item of the Third Schedule thereto, the following public works and property of each province, amongst others, shall be the property of Canada, namely "Canals with lands and water-power connected therewith."

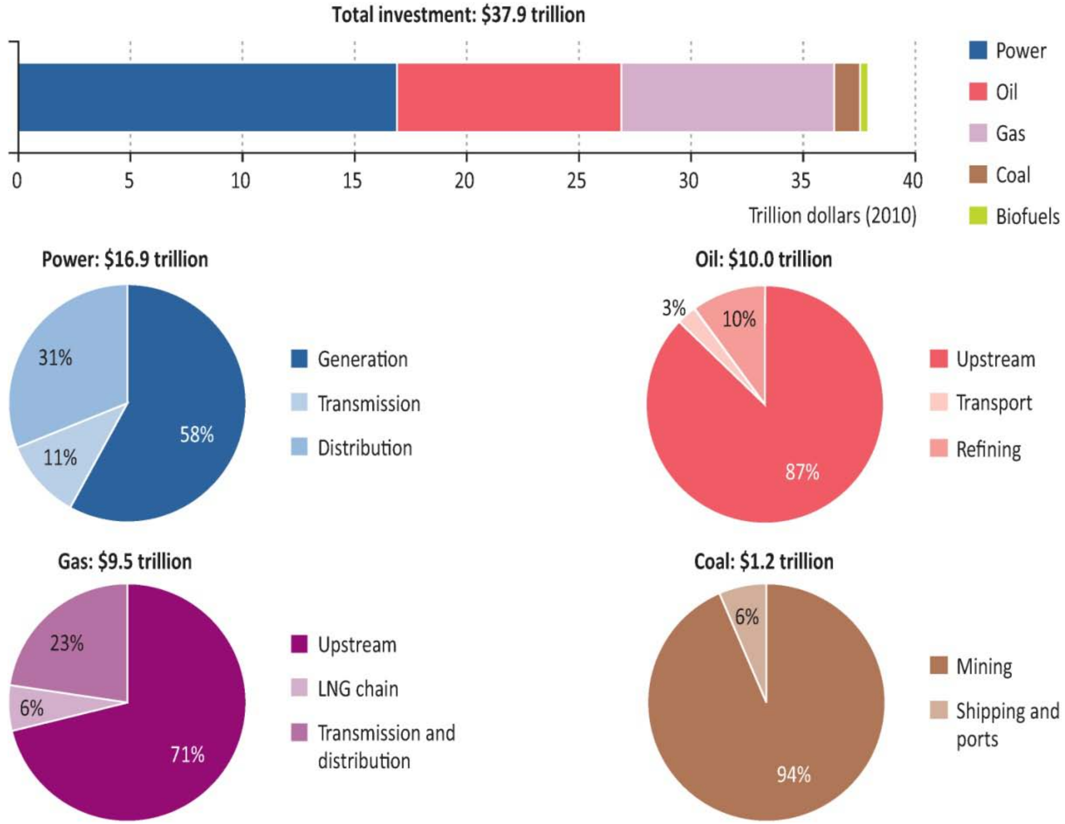
Has the province any proprietary interest in or beneficial ownership of or legislative control over the water-power which, though connected with the said canals, is created or made available by reason of extensions, enlargements or replacements of said canals made by the Dominion since Confederation and which is not required from time to time for the purpose of navigation?

Question 5. Where the bed of a navigable river is vested in the Crown in the right of the province, has the province any proprietary interest in or beneficial ownership of or legislative control over the water-power created or made available by works for the improvement of navigation constructed thereupon in whole or in part by or under the authority of the Dominion since Confederation which is not required from time to time for the purposes of navigation?

Investment: the essence of energy

WORLD ENERGY OUTLOOK 2011

Figure 2.20: Cumulative investment in energy-supply infrastructure by fuel in the New Policies Scenario, 2011-2035 (in year-2010 dollars)



Cumulative investment of $38 trillion – almost $1.5 trillion per year – is required in energy-supply investment to 2035, with 45% in the power sector alone

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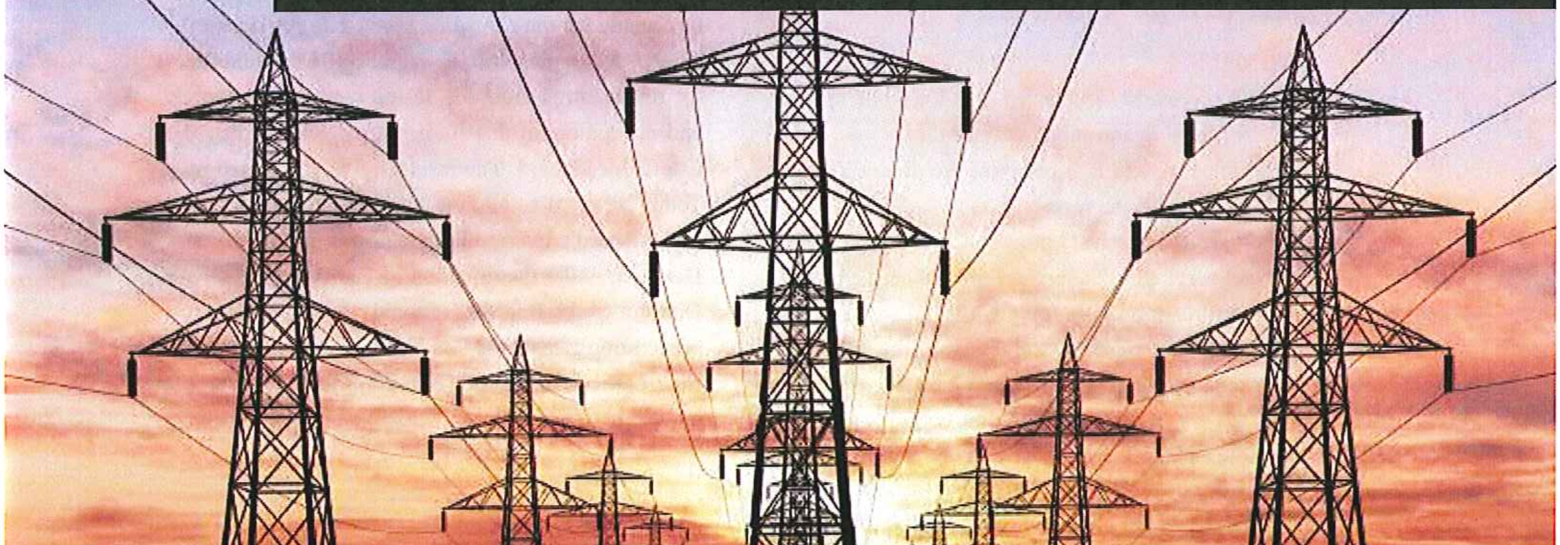
The Conference Board of Canada
Insights You Can Count On

Report February 2012



Shedding Light on the Economic Impact of Investing in Electricity Infrastructure

ECONOMIC PERFORMANCE AND TRENDS

The Conference Board of Canada
Insights You Can Count On

Shedding Light on the Economic Impact of Investing in Electricity Infrastructure
by *Len Coad*, *Todd Crawford*, and *Alicia Macdonald*

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Preface

This research was undertaken by The Conference Board of Canada for the Canadian Electricity Association (CEA). In keeping with Conference Board guidelines for financed research, the design method of research and the content of this study were determined by the Conference Board. The research was conducted by Todd Crawford and Alicia Macdonald, economists in the Board's Economic Forecasting and Analysis Division, under the direction of Pedro Antunes, Director of the Board's National and Provincial Forecasting group; and Len Coad, Director, Energy, Environment, and Transportation Policy.

CONTENTS

Acknowledgements

The authors of this study wish to express appreciation to Sandra Schwartz, Vice President, Policy Advocacy, at Canadian Electricity Association, and other individuals from CEA who contributed to the project by providing comments on several versions of the draft report. The report was also reviewed externally by Michelle Branigan, Executive Director, Electricity Sector Council. This project was funded by the Canadian Electricity Association. The authors wish to acknowledge that support. The analysis and conclusions of the report, along with any errors or omissions, are the authors' responsibility.

EXECUTIVE SUMMARY

Shedding Light on the Economic Impact of Investing in Electricity Infrastructure

At a Glance

- Investment in electricity infrastructure in Canada from 2011 to 2030 will total an estimated $347.5 billion, in current dollars.
- The direct, indirect, and induced impacts of that investment will add an average of $10.9 billion per year to real GDP and create an average of 156,000 jobs per year.
- In other words, for every $100 million (inflation adjusted) invested in electricity generation, transmission, and distribution infrastructure, real GDP will be boosted by $85.6 million and 1,200 jobs will be created.

Electricity generation, transmission, and distribution are a ubiquitous and integral part of any modern economy. Aside from providing households with all the conveniences of electric power, a modern and reliable electricity sector contributes to efficient overall economic production and plays an important role in determining Canada's competitive advantage. But in addition to its role of providing a source of energy, the electricity sector also contributes to lifting overall Canadian economic activity and employment through its capital investments in electricity infrastructure.

This report assesses the economic impact of potential future investment in electricity infrastructure in Canada. The methodology used allowed us to calculate economic multipliers—rules of thumb that link new investment in the sector to overall economic activity. The economic multipliers are valuable for planning because they link each dollar of additional investment by the industry to a given dollar value of overall economic output, job creation, and tax revenues. Moreover, this report links the occupational requirements of these increases to capital spending—highlighting the number of workers and skills needed to put in place future electricity generation, transmission, and distribution capacity.

A modern and reliable electricity sector contributes to efficient overall economic production.

The investment data used for this analysis were compiled in an earlier Conference Board report that examined capital investment in generation, transmission, and distribution capacity in each of Canada's provinces and territories. To determine the generation investments between now and 2030, a thorough search was performed to identify all generation units that are operational, under construction, planned, or proposed. Based on our estimates of retirements and refurbishments, we estimated the new construction required to ensure that future capacity increases align with future North American market requirements. Transmission investment estimates were based on company long-term plans, system operator long-term plans, and regulatory filings, but a lack of information suggests that transmission investments identified in this report are likely to be underestimated. Estimates for capital investment in distribution were based on sustaining existing infrastructure and meeting the requirements of expanding generation capacity. These capital investment estimates do not include increases to incorporate new technology, such as smart grids, or new uses of distributed electricity, such as electric cars.

Increased economic activity will lift household income and profits, boosting GDP in current dollars by an annual average of $21.3 billion from 2011 to 2030.

The analysis relied on results from Statistics Canada's national input-output model as well as simulations of the Conference Board's proprietary model of the national economy to determine the total economic impact resulting from new investment in electricity infrastructure from 2011 to 2030.

Cumulative investment in electricity infrastructure from 2011 to 2030 will total an estimated $347.5 billion, in current dollars. In real 2002 dollars, the total value of the projected investment will be $259.5 billion, an average of $13 billion per year. Not surprisingly, such a large increase in investment will have a widespread impact on the national economy. From 2011 to 2030, the average annual contribution to real gross domestic product (GDP), including direct, indirect, and induced impacts, will be $10.9 billion, and the contribution to employment will average 156,000 jobs per year. The impact would be even greater where it not for the sizable share of machinery and equipment investment that is expected to be imported from outside Canada.

The increased economic activity will lift household income and profits, helping to boost GDP in current dollars by an average of $21.3 billion per year from 2011 to 2030. A sizable benefit also accrues to the federal and provincial governments. In current dollar terms, the federal government balance will benefit from the increased economic activity by an average of $4.2 billion per year, while the aggregate provincial and territorial governments' balance will improve by an average of $1.9 billion per year from 2011 to 2030.

The labour requirements to accommodate the investment in electricity infrastructure will undoubtedly exert pressure on an already tight labour market. Employment in electric power engineering construction is expected to increase by an average of 49,000 jobs per year from 2011 to 2030. Since most of the investment is front-end loaded, the lift to employment will be most important over 2011 to 2016, when, on average, 75,359 jobs per year will be created in the electric power engineering construction sector.

Shedding Light on the Economic Impact of Investing in Electricity Infrastructure

INTRODUCTION

Electricity generation, transmission, and distribution are a ubiquitous and integral part of any modern economy. Aside from providing households with all the conveniences of electric power, a modern and reliable electricity sector contributes to efficient overall economic production and plays an important role in determining Canada's competitive advantage. But in addition to its role of providing a source of energy, the electricity sector also contributes to lifting overall Canadian economic activity and employment through its capital investments in electricity infrastructure.

This report assesses the economic impact of potential future investment in electricity infrastructure in Canada. The methodology used allowed us to calculate economic multipliers—rules of thumb that link new investment in the sector to overall economic activity. Under not too stringent conditions, the multipliers remain relatively stable under different capital investment scenarios. In other words, the economic multipliers are valuable for planning because they allow us to link each dollar of capital investment to a given dollar value of output, job creation, or tax revenues. In addition, census occupational databases were used to quantify future labour market requirements for electric power generation construction workers on an occupational basis.

An extensive nationwide survey on planned electricity infrastructure was conducted, allowing us to build estimates of capital investment spending on electricity generation, transmission, and distribution over the next two decades to 2030. Survey results provided planned additions to generation capacity, but these were also compared with anticipated future demand requirements to ensure that capacity increases aligned with future North American demand. Statistics Canada's input-output model was used to determine the first round, supply-chain impacts of this investment. The Conference Board of Canada's national forecasting model was then used to quantify the full economic impact on key indicators such as gross domestic product (GDP), employment, income, and government revenues.

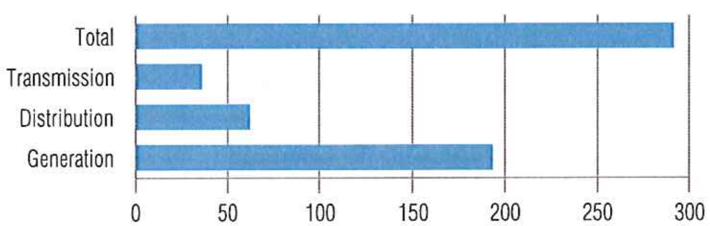
INVESTMENT DATA AND METHODOLOGY

The investment data used for this analysis were compiled in an earlier Conference Board report that examined capital investment in generation, transmission, and distribution capacity in each of Canada's provinces and territories.[1] To determine the generation investments between now and 2030, a thorough search was performed to identify all generation units that are operational, under construction, planned, or proposed. Based on our estimates of retirements and refurbishments, we estimated the new construction required to ensure that future capacity increases align with future North American market requirements. Transmission investment estimates were based on company long-term

1 Baker and others, *Canada's Electricity Infrastructure: Building a Case for Investment.*

plans, system operator long-term plans, and regulatory filings, but a lack of information suggests that transmission investments identified in this report are likely to be underestimated. Estimates for capital investment in distribution were based on sustaining existing infrastructure and for meeting the requirements of expanding generation capacity. These capital investment estimates do not include increases to incorporate new technology, such as smart grids, or new uses of distributed electricity, such as electric cars. The total investment in electricity infrastructure over 2010 to 2030 will be nearly $300 billion (in 2010 dollars), with the majority of the investment occurring in generation capacity. (See Chart 1.)

Chart 1
Electricity Infrastructure Investment from 2010 to 2030
(2010 $ billions)



Source: The Conference Board of Canada.

GENERATION INVESTMENT

Each province and territory faces different future needs with regard to installed generation capacity, the mix of generation technologies, the timing of new investments, the governing policy framework, and whether the capacity additions will be funded by private or public organizations.

The starting point for generation investments in each jurisdiction is the level and age distribution of currently installed capacity for each generation technology. Assumptions about asset life and retirement or refurbishment options were applied to existing capacity to determine the investments required in those categories. In addition, pending federal regulations for coal-fired generation would require each unit to meet a "clean as natural gas" emissions standard at the end of the economic life of the unit or the end of its power purchase agreement, whichever comes first. New coal units coming into service after 2015 would be required to meet the same standard.[2] The working assumption for this analysis is that coal-fired units that have not been scheduled for retirement will be repowered with some form of clean coal technology.[3] All other units are assumed to be repowered with the same energy source they currently use. For units that are to be retired, the required investments are included.

Estimates for capital investment in distribution were based on sustaining existing infrastructure and meeting the requirements of expanding generation capacity.

The next tranche of generation investment is for projects that are under construction or are at an advanced planning stage—that is, they have been approved by the appropriate regulator or planning authority. These projects are not all guaranteed to be built but carry a high probability of completion. For these projects, the capital cost estimates were based on published data for each generation technology, together with the announced target for installed capacity for each project.

The final tranche of generation investment relates to projects that have been proposed or announced. This category includes thousands of projects, many of which are highly uncertain. Considerable judgment must be applied to determine the level of investment that might occur in this group of projects. For each technology, the capital cost per megawatt of installed capacity was estimated, based on recently completed projects.

2 According to Environment Canada, the proposed regulation requires all existing coal-fired electricity generation units, upon reaching end of economic life, to meet a carbon dioxide (CO_2) emission standard of 375 tonnes per gigawatt-hour (GWh). If a unit cannot meet the Natural Gas Combined Cycle (NGCC) standard, it will be required to shut down. New units will be also required to meet the NGCC standard. However, the standard will not apply to new generation until the year 2025, provided it is carbon capture and storage (CCS) ready. The proposed regulations will be promulgated under the *Canadian Environmental Protection Act* (CEPA) and will come into effect on July 1, 2015. Details of the program announcement can be found at www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=2E5D45F6-E0A4-45C4-A49D-A3514E740296.

3 In building the investment assumptions, we have assumed, based on previous research, that clean coal technologies will improve sufficiently to meet the standard at a cost that is roughly 10 per cent lower than that of new nuclear facilities.

These capital costs were applied to the estimated installed capacity for each technology to determine the overall investment in new generation capacity.

The level of projected future demand for energy was based on the potential for growth in domestic and export markets for each of the provinces and territories. However, because market requirements are for energy, not capacity, an assumed capacity factor was applied to determine the installed capacity required to meet future demands. The capacity factors were estimated by technology for each province and territory, and were based on historical performance.

The level of projected future demand for energy was based on the potential for growth in domestic and export markets for each of the provinces and territories.

The overall level of capacity from new construction was then estimated based on the balance between required capacity and the sum of installed capacity (including retirements, refurbishments, and repowering) plus capacity under construction or at advanced planning stages. The mix of technologies differed in each province, based on installed capacity, technology-related policy frameworks, the mix of technologies within the set of announced projects, and a general understanding of the ability of the transmission grid to integrate additional renewable energy in particular.

The mix of generation technologies and capacities included in the investment profile for each province and territory is shown in Table 1. These investments reflect the best available information, plus some necessary assumptions. For example, the investment data are based on the Lower Churchill hydroelectric project in Labrador proceeding as currently planned. Also, any coal stations with announced retirement dates are assumed to be replaced by clean coal technologies, and all future coal retirements are based on an assumed service life applied to the original plant commissioning date.

The required generation investments by province are shown in Table 2.

TRANSMISSION INVESTMENT

The level of future investment in transmission capacity was based on announced projects in each province or territory. Planning horizons differ widely in each, with very few investment streams covering the entire period through 2030. Because transmission investments are project-specific, this report did not estimate investments beyond identified projects through the rest of the period. This means the $35.8-billion estimate of transmission investment understates the level of future investment that will likely be required. (See Table 3.)

There is also the potential for a mismatch between the generation investments assumed and the transmission investments that will be required to integrate long-term future generation projects into the grid. This mismatch would likely be greatest in jurisdictions where a significant portion of future generation investments is in wind and solar and the existing grid is designed primarily around thermal generation sources. The cost of integrating these variable sources is subject to uncertainty.

The $35.8-billion estimate of transmission investment likely understates the future investment required.

The transmission investments in this report do not include the impact of smart grid programs[4] unless those programs are included in published investment plans. Given the very early stage of smart grid development and the focus to date on downstream investments (mainly smart meters in homes and workplaces), we do not believe the numbers in Table 3 reflect the smart grid investments that will eventually be made.

4 The Canadian Electricity Association defines the smart grid as "a suite of information-based applications made possible by increased automation of the electricity grid, as well as the underlying automation itself; this suite of technologies integrates the behaviour and actions of all connected supplies and loads through dispersed communication capabilities to deliver sustainable, economic and secure power supplies." McCarthy, *The Smart Grid: A Pragmatic Approach*, 5.

Table 1
Generation Capacity Included in Investments
(MW)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Coal	0	1,376	0	0	0	0	0	0	0	0	0	0	0	1,376
Nuclear	0	0	0	0	3,500	0	0	40	0	0	0	0	0	3,540
Large hydro	3,223	147	250	2,380	862	3,350	0	0	3,153	0	10	10	0	13,385
Natural gas	72	4,163	346	0	4,243	0	0	0	50	0	0	0	0	8,874
Biomass	138	0	182	0	77	0	180	0	0	0	0	0	0	577
Landfill or biogas	0	0	0	0	15	0	0	0	0	0	0	0	0	15
Diesel	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-grid hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small hydro	51	0	0	0	306	29	100	0	0	0	0	0	0	486
Waste heat	0	100	0	0	0	0	0	45	125	0	0	0	0	270
Wind	1,595	1,159	242	138	2,178	2,666	970	454	0	130	0	0	0	9,532
Wind, offshore	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	100	0	0	0	0	0	0	0	0	0	0	0	0	100
Solar	0	0	0	0	964	0	0	0	0	0	0	0	0	964
Other or unkown fuel	0	0	0	0	0	0	0	0	268	0	0	0	0	268
Total	**5,179**	**6,945**	**1,020**	**2,518**	**12,145**	**6,045**	**1,250**	**539**	**3,596**	**130**	**10**	**10**	**0**	**39,386**

Source: The Conference Board of Canada.

Table 2
Investments in Generation Capacity
(2010 $ millions)

	B.C.	Alta.	Sask.	Man.	Ont.	Que.	N.S.	N.B.	N.L.	P.E.I.	Y.T.	N.W.T.	Nun.	Canada
Refurbishment/ repowering	2,955	26,427	7,639	1,410	18,926	10,814	2,776	283	2,621	345	14	1	18	74,229
Retirement	342	677	3	0	3,711	0	135	11	205	0	0	0	0	5,085
New construction	16,131	16,914	2,782	8,647	37,214	17,916	3,151	1,314	11,911	299	35	35	0	116,348
Total	**19,428**	**44,019**	**10,423**	**10,057**	**59,851**	**28,730**	**6,062**	**1,608**	**14,736**	**644**	**49**	**36**	**18**	**195,662**

Source: The Conference Board of Canada.

DISTRIBUTION INVESTMENT

This report's approach to determining investments in distribution systems was also more generic than for investments in generation. Distribution systems typically separate their investment plans between sustaining and growth categories (with additional investments in administration and information technologies). Sustaining investments can be estimated based on the gross plant in service and depreciation assumptions. Growth investments can be estimated based on the assumed growth in electricity demand and the historical trend in investment per unit of energy delivered. This report assumes a total investment in distribution facilities of $62.3 billion between 2010 and 2030 as detailed in Table 4.

Table 3
Investments in Transmission Capacity
(2010 $ millions)

Province	Total investments identified	Information Sources	Time Horizon
British Columbia	4,330	◆ BC Transmission Corporation Capital Plan 2009–18 ◆ Fortis 2005–2024 Transmission and Distribution System Development Plan ◆ British Columbia Utilities Commission decision reports	2010–2018 2011–2024 2011
Alberta	16,654	◆ Alberta Electric System Operator (AESO) Long-Term Transmission System Plan ◆ Alberta Utilities Commission (AUC) decisions and pending applications	2010–2020 2010–2015
Saskatchewan		◆ Project costs not published	
Manitoba	3,535	◆ Manitoba Hydro 2010–2011 and 2011–2012 Rate Application Tab 6	2010–2018
Ontario	5,481	◆ Hydro One Capital Plan ◆ Integrated Power System Plan, Section E ◆ Ontario's Long-Term Energy Plan	2010–2012 2010–2020 2010–2030
Quebec	3,805	◆ Hydro-Québec TransÉnergie 2009–2013 Strategic Plan	2009–2013
Nova Scotia	1,700	◆ Nova Scotia Power 10-Year System Outlook	2010–2015
New Brunswick	88	◆ NBSO 10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities in New Brunswick 2011–2021	2010–2018
Newfoundland and Labrador	244	◆ 2010 Capital Budget Application, prepared by Newfoundland and Labrador Hydro	2010–2030
Prince Edward Island		◆ Project costs not published	
Total announced investment	**35,838**		

Source: The Conference Board of Canada.

ECONOMIC IMPACT METHODOLOGY

This report quantifies the economic impact of new investment in electricity infrastructure on the national economy over the next 20 years.

It is important to note that the capital investment data described in the previous section were converted from 2010 dollars to 2002 dollars to determine the economic impact of the investment. This was necessary because 2002 is the base year that Statistics Canada has adopted for the National Income Accounts.

Next, a simulation was produced using Statistics Canada's input-output model of the Canadian economy. This simulation provides the supply-chain (or indirect) impacts of investment in machinery and equipment and structures in the utilities industry. Finally, the Conference Board's national forecasting model was simulated to determine the

Table 4
Distribution Investments
(2010 $ millions)

	Sustaining	Growth	Total
British Columbia	2,536	1,540	4,076
Alberta	8,016	2,745	10,761
Saskatchewan	631	22	652
Manitoba	2,122	317	2,439
Ontario	16,636	3,966	20,602
Quebec	19,298	2,371	21,669
Nova Scotia	428	240	668
New Brunswick	618	284	902
Newfoundland and Labrador	357	61	418
Prince Edward Island	44	22	66
Yukon	12	5	18
Northwest Territories	24	16	40
Nunavut	5	1	6
Canada	**50,727**	**11,590**	**62,316**

Source: The Conference Board of Canada.

total economic impact of the projected new investment. The analysis evaluated the combined direct, indirect, and induced economic impacts:

- **Direct impacts** measure the value-added[5] from the construction of the new infrastructure; they are the impacts directly attributed to the employees, the wages earned, and the firms' revenues generated by the construction.
- **Indirect impacts** relate to determining the value that the investment generates economically for other industries through the supply chain. For example, increased construction activity will boost demand for intermediate inputs and generate increased activity in the transportation sector.
- **Induced impacts** are derived from the purchases of employees and reinvestment of profits from both the construction and supplier industries. These (usually smaller) impacts lead to more employment, wages, income, and tax revenues and have widespread impacts on the economy.

5 Value-added or net output is the difference between total revenue and the sum of expenses on parts, materials, and services used in the production process. Summing the value-added across all industries in a region will yield the GDP in that region.

In effect, increased demand for a specific industry will not only have direct impacts on the economy but will also spread through the economy through a series of multiplier effects. Indirect effects are first felt because of an increase in demand for products and services from industries that are direct suppliers. Second-round induced effects produce a smaller but more widespread impact on all sectors of the economy, largely through a general increase in consumer spending.

To more accurately assess the direct and indirect value-added impact on related industries, the analysis relied on the use of Statistic Canada's national model of Canada's industrial structure. This input-output model of the Canadian economy has the advantage of finely detailing the industrial structure within Canada's economy as well as containing linkages for inputs that are imported.

Increased demand for a specific industry will have direct impacts on the economy and will also spread through the economy through a series of multiplier effects.

While the Conference Board's national forecasting model contains a more aggregate industrial sector, it has the benefit of assessing the impact of additional income, through changes in wages and profits, on a wide range of economic indicators. Moreover, the Conference Board's models allow for the analysis to be carried out over a time period, whereas Statistics Canada's input-output model produces a point-in-time measure of the impact. The direct and indirect effects obtained from the input-output model simulations were used as guides when simulating the Conference Board's model of the national economy to produce the overall economic impact of potential investment in electricity infrastructure over 2011 to 2030.

Once the model simulations were complete, the Conference Board used the results for the total increase in construction employment to determine the increase in employment in the electric power engineering construction industry and what this means in terms of increased demand by occupation. A number of simplifying assumptions were necessary to estimate the potential increase in employment by occupation resulting from the capital investment required.

As a first pass, results from the input-output model were used to determine the share of total employment in construction directly associated with electric power engineering construction. Next, we used data from the National Occupational Classification System (NOCS) database to project employment requirements by occupation. The NOCS data are currently only available from the 2006 Census. The projections must rely on the simplifying assumption that occupational shares have been constant since 2006 and will remain constant over the forecast horizon. In addition, the NOCS data were gathered with a sample that represents 20 per cent of the employment, and so the sum of occupational categories in the original data does not necessarily equal the total by broader occupational grouping. Therefore, it was necessary to constrain the more detailed two-digit-level NOCS data to sum to the more general one-digit NOCS employment data classified as electric power engineering construction as shown in Appendix A.

These occupational shares were then applied to our forecast for electric power engineering construction employment to derive the estimates of employment by occupation.

FINDINGS

Cumulative investment in electricity infrastructure from 2011 to 2030 will total an estimated $347.5 billion, in current dollars. In real 2002 dollars, the cumulative value of the projected investment will be $259.5 billion, with $144.4 billion invested in structures and $115.1 billion in machinery and equipment.

Not surprisingly, the future investment spending requirements will have widespread impacts on the Canadian economy. From 2011 to 2030, the average contribution to real GDP—including direct, indirect, and induced impacts—will be $10.9 billion per year, and the contribution to employment will average 156,000 jobs per year. Table 5 summarizes the impact of the investment on key economic indicators.

Investment will peak over the first five years of the forecast horizon, when the increase in nominal investment spending is projected to average $22.7 billion per year. The impact of this investment will lift real GDP in the economy by an annual average of $16.1 billion contributing, on average, about 1.2 per cent per year to the Canadian economy. This activity will support an average of 247,000 jobs per year over 2011–2015. By 2026–2030, annual investment in nominal terms is expected to average $13.9 billion. During this period, the average annual impact on real GDP will be $7.6 billion, supporting roughly 97,000 jobs per year.

From 2011 to 2030, the average contribution to real GDP will be $10.9 billion per year, and the contribution to employment will average 156,000 jobs per year.

The sizable share of machinery and equipment investment expected to be imported from outside Canada will limit the overall impact on Canada's economy. Moreover, higher domestic prices resulting from the increase in overall economic activity will make Canadian exports less competitive, resulting in a mildly negative impact on exports. Overall, the impact analysis suggests that the impact on trade flows will reduce the current account balance by an average of $7.2 billion (current dollars) per year.

The increase in employment will push personal income in current dollars up by an annual average of $9.2 billion from 2011 to 2030, while corporate profits will be $2.7 billion higher per year on average. Increases in personal income and corporate profits will help to push GDP in current dollars up by an average of $21.3 billion per year from 2011 to 2030.

A sizable benefit will also accrue to the federal and provincial governments. The boost to personal incomes will result in an average annual increase of $1.5 billion in personal income tax collection, while increases in profits will yield an average increase of $840 million per year in corporate income taxes over 2011 to 2030 for the federal

Table 5
Impact of Electricity Investment on Key Economic Indicators
(level difference of shock minus control, except where otherwise indicated; average per year over each five-year period)

	2011–15	2016–20	2021–25	2026–30
Increase in investment ($ millions)	22,749	17,228	15,615	13,912
Increase in investment (2002 $ millions)	19,772	13,109	10,397	8,623
Real GDP (2002 $ millions at market prices)	16,081	11,015	8,995	7,632
GDP ($ millions)	22,981	21,013	20,731	20,568
GDP deflator (percentage change)	0.1	0.2	0.2	0.2
Consumer price index (percentage change)	0.1	0.1	0.1	0.1
Average weekly wages industrial composite (percentage change)	0.1	0.1	0.1	0.1
Employment (000s)	247	160	118	97
Unemployment rate (per cent)	–1.1	–0.8	–0.6	–0.5
Personal income ($ millions)	12,247	9,163	7,887	7,474
Pre-tax corporate profits ($ millions)	2,973	2,586	2,646	2,590
90-day Treasury bill rate (per cent)	0.1	0.1	0.1	0.1
Current account balance ($ millions)	–8,320	–7,172	–6,525	–6,646
Personal income tax ($ millions)	1,829	1,399	1,239	1,368
Corporate income tax ($ millions)	907	812	818	824
Indirect taxes ($ millions)	1,300	1,259	1,060	1,080
Federal govt. balance ($ millions)	3,683	3,551	4,123	5,299
Regional govt. balance ($ millions)	2,378	2,051	1,669	1,609

Source: The Conference Board of Canada.

and provincial governments. Indirect taxes (which consist largely of sales taxes) will be boosted by the lift to income and consumer spending, increasing by an average of $1.2 billion per year over the forecast horizon. In current dollar terms, the federal government balance stands to improve by an average of $4.2 billion per year, while the provincial and territorial governments' balance is forecast to increase by an annual average of $1.9 billion from 2011 to 2030. Our analysis suggests that prices and interest rates will increase modestly in response to the increase in economic activity, acting to slightly dampen the positive economic impacts.

Table 6 shows the impact of increased investment on the components of real GDP by spending category. The direct impact of the shock—that is, the impact of electricity infrastructure investment using our economic modelling—is on private capital investment on structures and on machinery and equipment, which will increase by an annual average of $7.2 billion and $5.9 billion respectively over 2011 to 2030. However, the large import component associated with the initial hit to machinery and equipment investment represents a leakage that will offset the overall impact on Canada's economy. Additional imports are required to meet the extra demand for consumer goods resulting from increased employment and income. As a result of this extra demand, imports will increase by an average of $6 billion per year from 2011 to 2030, dampening the total impact on real GDP. The trade balance will be further eroded by a small decline in exports as higher domestic prices will reduce our ability to compete internationally, putting downward pressure on export volumes. But increased income will result in a small boost to residential construction, while higher inventories will add modestly to the increase in real GDP. Government spending will be unaffected, aside from the direct capital electricity infrastructure investment.

Economic impact results on GDP by industry are presented in Table 7. The largest impact will be on the construction industry, which will increase by an average of $3.8 billion per year. Manufacturing industries will also experience a sizable boost, with sectors such as the fabricated metals industry and the electrical equipment and component manufacturing industry benefiting from the investment. Private sector services industries will also experience an increase in demand for services that include architecture, engineering, and computer system design. The services sector will also benefit from the induced impacts when higher employment and wages lead to an increase in consumer demand. In total, output in business services is expected to increase by an average of $5.3 billion per year over 2011 to 2030.

Table 6
Impact of Electricity Investment on Components of GDP
(level difference of shock minus control, except where otherwise indicated; average per year over each five-year period; 2002 $ millions at market prices)

	2011–15	2016–20	2021–25	2026–30
Consumer spending	2,667	2,531	2,129	2,296
Total government spending	1	1	1	2
Private capital investment	22,712	14,386	11,020	8,408
Structures	11,063	7,566	5,890	4,440
Machinery and equipment	9,643	5,332	4,252	4,247
Residential construction	295	262	245	222
Final domestic demand	23,487	16,197	13,011	11,222
Change in inventories	397	263	209	173
Exports	–177	–187	–191	–196
Imports	8,523	6,066	4,798	4,475
Net exports	–8,700	–6,253	–4,989	–4,671
GDP at market prices	16,081	11,015	8,995	7,632

Source: The Conference Board of Canada.

Many jobs will be created in construction and large gains will also accrue in commercial services industries, including wholesale and retail trade industries.

The overall economic multiplier is calculated as the total change in real GDP divided by the initial constant dollar increase in investment in electricity infrastructure. Because of the large import leakages, the multiplier is less than one. Our estimates indicate that for every $100 million (inflation adjusted) invested in electricity generation, transmission, and distribution infrastructure, real GDP will be boosted by $85.6 million, and roughly 1,200 person-years of employment will be created.

Overall, employment will increase by an average of 156,000 jobs per year from 2011 to 2030 as a result of the investment in electricity infrastructure. The multiplier yields an estimate of total employment generated (measured in person-years of employment) for every $100 million of real infrastructure spending.

In other words, for each $100 million invested, 1,200 jobs will be created for one year. Employment gains will peak in the first five years of the analysis: from 2011 to 2015, the lift to economic activity resulting from cumulative investment in electricity infrastructure over that period will be roughly 247,000 people employed in each year.

Table 8 breaks down the employment gains by industry. Construction accounts for the largest single share of employment gains. Construction employment peaks during the first five years of the analysis with an average of about 95,000 jobs created in the construction industry over 2011 to 2030. By the 2026 to 2030 period, the annual contribution to construction employment will drop to fewer than 40,000. While many jobs will be created in the construction industry, large gains will also accrue in commercial services industries, including wholesale and retail trade industries. In this scenario, the number of unemployed people will be reduced by an average of 150,000, pushing the unemployment rate down by an average of 0.7 percentage points per year.

Table 7
Impact of Electricity Investment on GDP by Industry
(level difference of shock minus control, except where otherwise indicated; average per year over each five-year period; 2002 $ millions at basic prices)

	2011–15	2016–20	2021–25	2026–30
Real GDP at basic prices	17,080	11,175	8,841	7,406
Total goods	8,730	5,641	4,410	3,687
Primary	557	375	295	242
Utilities	215	146	115	94
Construction	5,879	3,751	2,925	2,449
Manufacturing	2,079	1,369	1,075	902
Business services	8,029	5,312	4,256	3,573
Wholesale and retail trade	2,571	1,588	1,296	1,083
Transportation and warehousing	571	375	294	245
Information and cultural services	414	271	213	183
Finance, insurance and real estate	2,026	1,425	1,151	944
Professional, scientific and technical	1,385	930	736	627
Other business services	1,062	722	566	490
Public sector	320	222	175	146
Multiplier	**0.86**	**0.85**	**0.85**	**0.86**

Source: The Conference Board of Canada.

Table 8
Impact of Electricity Investment on the Labour Market
(level difference of shock minus control, except where otherwise indicated; average per year over each five-year period; 000s)

	2011–15	2016–20	2021–25	2026–30
Total employment	247.2	159.8	118.2	97.4
Primary	3.6	2.3	1.6	1.2
Construction	95	64.1	46.8	39
Utilities	1.1	0.7	0.5	0.4
Manufacturing	20.6	12.8	9.4	7.4
Other commercial services	62.4	40.7	30.6	25.6
Wholesale and retail trade	44.5	25.2	19.1	15.3
Transportation and storage	7.4	4.8	3.5	2.8
Finance, insurance, and real estate	8.1	5.8	4.4	3.6
Public sector	4.5	3.5	2.5	2.1
Unemployed	–221	–156	–121	–102
Unemployment rate (%)	–1.1	–0.8	–0.6	–0.5

Source: The Conference Board of Canada.

The labour requirements to accommodate the investment in electricity infrastructure will undoubtedly exert pressure on an already tight labour market. According to the Construction Sector Council's 2011 forecast, the construction industry will need to recruit 111,000 workers between 2011 and 2019 and also replace close to 208,000 workers who will leave the industry because of retirement or mortality. The council estimates there will not be enough supply to meet this demand, and solutions are being investigated as to how this shortfall could potentially be bridged.[6] Given these pressures, it is important to identify the specific occupational requirements resulting from any additional capital investment in electric power generation, transmission and distribution—providing a sense of labour market requirements for future increases in capital spending.

The labour requirements to accommodate the investment in electricity infrastructure will undoubtedly exert pressure on an already tight labour market.

Detailed simulation results using Statistics Canada's input-output model suggest that 80 per cent of the lift to construction employment will be directly attributable to electric power engineering construction. Thus, employment in electric power engineering construction is expected to increase by an average of 49,000 jobs per year from 2011 to 2030. Since most of the investment is front-end loaded, the lift to employment will be most important over 2011 to 2016, when, on average, 75,359 jobs will be created in the electric power engineering construction sector per year. (See Table 9.)

The increase to construction employment will encompass a wide range of occupations, as shown in Table 9. The largest impact will be on the trades, transport, and equipment operators and related occupations, where an average of 52,000 jobs per year will be created from 2011 to 2015.

6 Construction Sector Council, *Meeting Construction and Maintenance Workforce Challenges: Construction Owners Strategy 2011 to 2016*, 15.

Breaking this out for a few subcategories suggests there will be sizable annual employment impacts in the following: trades helpers, construction, and transportation labourers and related occupations (11,200); heavy equipment and crane operators, including drillers (10,800); and construction trades (9,100). (See Appendix A for more details.)

CONCLUSION

This report builds on an earlier report produced by the Conference Board on Canada's electricity infrastructure.[7] In our earlier study, we carefully considered numerous sources to estimate the future capital investments in electricity infrastructure over the next 20 years. This report follows on our earlier research by assessing, over the 2011 to 2030 period, the potential contribution to economic activity of these investments. Economic models were used to quantify the overall impact on GDP, employment, government revenues, and other economic indicators.

The results highlight, at an aggregate level, the widespread effects that capital investment in electricity generation, transmission, and distribution will have across all sectors of the economy. Our analysis assumes that $347.5 billion in current dollars will be spent on new electricity infrastructure from 2011 to 2030. This translates into an average of $13 billion per year when converted to 2002 dollars (inflation-adjusted dollars). And, when accounting for direct, indirect, and induced impacts, this investment is projected to contribute roughly $10.9 billion per year to real GDP.

In other words, for every $100 million (inflation adjusted) invested in electricity generation, transmission, and distribution infrastructure, real GDP will be boosted by $85.6 million, and roughly 1,200 person-years of employment will be created. These economic multipliers are valuable for planning because they link each dollar of additional investment by the industry to a given dollar value of output, job creation, or tax revenues.

7 Baker and others, *Canada's Electricity Infrastructure.*

Table 9
Impact of Electricity Investment on Employment in Electric Power Engineering Construction
(average increase per year over each five-year period)

	2011–15	2016–20	2021–25	2026–30
Overall employment in electric power engineering construction	**75,359**	**50,801**	**37,086**	**30,915**
Management occupations	5,756	3,881	2,833	2,362
Business, finance, and administrative occupations	8,086	5,451	3,979	3,317
Natural and applied sciences and related occupations	5,260	3,546	2,589	2,158
Health occupations	95	64	47	39
Occupations in social science, education, government services, and religion	143	97	70	59
Occupations in art, culture, recreation, and sport	86	58	42	35
Sales and service occupations	1,031	695	507	423
Trades, transport and equipment operators, and related occupations	51,675	34,835	25,430	21,199
Occupations unique to primary industry	2,616	1,763	1,287	1,073
Occupations unique to processing, manufacturing and utilities	611	412	301	251

Sources: The Conference Board of Canada; Statistics Canada, 2006 Census, Catalogue Number 97-564-XCB2006006.

Over the 2011 to 2015 period, when capital investment activity is expected to peak, real GDP will be lifted by over $16 billion per year, contributing, on average, about 1.2 per cent per year to the Canadian economy. This is a sizable impact that occurs in addition to the contribution that electric power generation itself brings to the economy. Moreover, this activity supports an average of 247,000 jobs per year over 2011 to 2015. Capital investment spending will ease over the forecast horizon. Still, over the 2026–2030 period, construction activity related to electricity infrastructure will still support employment for 97,000 workers annually.

Capital investment activity supports an average of 247,000 jobs per year over 2011 to 2015.

The labour requirements to accommodate the investment in electricity infrastructure will undoubtedly exert pressure on an already tight labour market. According to the Construction Sector Council, demand for construction workers is expected to exceed supply over the next decade. This suggests that the electric power generation industry in Canada may encounter supply constraints when adding to new generation capacity or when refurbishing existing facilities. Therefore, it is important to identify the occupational requirements resulting from any additional capital investment in electric power infrastructure. Our analysis shows that this investment will increase the demand in particular for tradespeople and for transport and equipment operators.

Employment in electric power engineering construction is expected to increase by an average of 49,000 jobs per year from 2011 to 2030. Since most of the investment is front-end loaded, the lift to employment will be most important over 2011 to 2016, when, on average, 75,359 jobs per year will be created in the electric power engineering construction sector. More specifically, the largest impact will be on the trades, transport, and equipment operators and related occupations, where an average of 52,000 jobs per year will be created from 2011 to 2015. Within this category, the most sizable annual employment impacts will be in the following subcategories: trades helpers, construction, and transportation labourers and related occupations (11,200 jobs); heavy equipment and crane operators, including drillers (10,800 jobs); and construction trades (9,100 jobs).

APPENDIX A

Impact of Electricity Investment on Employment in Electric Power Engineering Construction

Table 1
Impact of Electricity Investment on Employment in Electric Power Engineering Construction
(average increase per year over each five-year period)

Employment in Electric Power Engineering Construction	2011–15	2016–20	2021–25	2026–30
TOTAL	75,359	50,801	37,086	30,915
A. Management occupations	**5,756**	**3,881**	**2,833**	**2,362**
A0. Senior management occupations	897	605	442	368
A1. Specialist managers	1,088	734	536	446
A2. Managers in retail trade, food, and accommodation services	67	45	33	27
A3. Other managers, not elsewhere classified (n.e.c.)	3,704	2,497	1,823	1,520
B. Business, finance, and administrative occupations	**8,086**	**5,451**	**3,979**	**3,317**
B0. Professional occupations in business and finance	554	374	273	227
B1. Finance and insurance administrative occupations	736	496	362	302
B2. Secretaries	1,309	883	644	537
B3. Administrative and regulatory occupations	1,596	1,076	785	655
B4. Clerical supervisors	191	129	94	78
B5. Clerical occupations	3,699	2,493	1,820	1,517
C. Natural and applied sciences and related occupations	**5,260**	**3,546**	**2,589**	**2,158**
C0. Professional occupations in natural and applied sciences	2,005	1,351	987	822
C1. Technical occupations related to natural and applied sciences	3,255	2,194	1,602	1,335
D. Health occupations	**95**	**64**	**47**	**39**
D0. Professional occupations in health	–	–	–	–
D1. Nurse supervisors and registered nurses	–	–	–	–
D2. Technical and related occupations in health	76	51	38	31
D3. Assisting occupations in support of health services	19	13	9	8

(continued . . .)

Table 1
Impact of Electricity Investment on Employment in Electric Power Engineering Construction (cont'd)
(average increase per year over each five-year period)

Employment in Electric Power Engineering Construction	2011–15	2016–20	2021–25	2026–30
E. Occupations in social science, education, government service, and religion	**143**	**97**	**70**	**59**
E0. Judges, lawyers, psychologists, social workers, ministers of religion, and policy and program officers	124	84	61	51
E1. Teachers and professors	19	13	9	8
E2. Paralegals, social services workers and occupations in education and religion, n.e.c.	–	–	–	–
F. Occupations in art, culture, recreation, and sport	**86**	**58**	**42**	**35**
F0. Professional occupations in art and culture	52	35	25	21
F1. Technical occupations in art, culture, recreation, and sport	34	23	17	14
G. Sales and service occupations	**1,031**	**695**	**507**	**423**
G0. Sales and service supervisors	–	–	–	–
G1. Wholesale, technical, insurance, real estate sales specialists, and retail, wholesale and grain buyers	124	84	61	51
G2. Retail salespersons and sales clerks	229	154	113	94
G3. Cashiers	–	–	–	–
G4. Chefs and cooks	76	51	38	31
G5. Occupations in food and beverage service	–	–	–	–
G6. Occupations in protective services	162	109	80	67
G7. Occupations in travel and accommodation, including attendants in recreation and sport	–	–	–	–
G8. Child care and home support workers	–	–	–	–
G9. Sales and service occupations, n.e.c.	439	296	216	180
H. Trades, transport and equipment operators, and related occupations	**51,675**	**34,835**	**25,430**	**21,199**
H0. Contractors and supervisors in trades and transportation	6,427	4,333	3,163	2,637
H1. Construction trades	9,149	6,167	4,502	3,753
H2. Stationary engineers, power station operators, and electrical trades and telecommunications occupations	6,274	4,230	3,088	2,574
H3. Machinists, metal forming, shaping, and erecting occupations	3,457	2,330	1,701	1,418
H4. Mechanics	1,509	1,017	743	619
H5. Other trades, n.e.c.	888	599	437	364
H6. Heavy equipment and crane operators, including drillers	10,820	7,294	5,325	4,439
H7. Transportation equipment operators and related workers, excluding labourers	1,948	1,313	959	799
H8. Trades helpers, construction, and transportation labourers and related occupations	11,202	7,552	5,513	4,596

(continued . . .)

Table 1
Impact of Electricity Investment on Employment in Electric Power Engineering Construction (cont'd)
(average increase per year over each five-year period)

Employment in Electric Power Engineering Construction	2011–15	2016–20	2021–25	2026–30
I. Occupations unique to primary industry	**2,616**	**1,763**	**1,287**	**1,073**
I0. Occupations unique to agriculture, excluding labourers	163	110	80	67
I1. Occupations unique to forestry operations, mining, oil and gas extraction, and fishing, excluding labourers	929	627	457	381
I2. Primary production labourers	1,523	1,027	750	625
J. Occupations unique to processing, manufacturing, and utilities	**611**	**412**	**301**	**251**
J0. Supervisors in manufacturing	87	59	43	36
J1. Machine operators in manufacturing	339	229	167	139
J2. Assemblers in manufacturing	68	46	33	28
J3. Labourers in processing, manufacturing, and utilities	116	78	57	48

Sources: The Conference Board of Canada; Statistics Canada, 2006 Census, Catalogue Number 97-564-XCB2006006.

APPENDIX B

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SCHEDULE 2.0-T

ATCO Electric

SUMMARY OF RETURN ON RATE BASE (TRANSMISSION)

FOR THE YEAR ENDED DECEMBER 31, 2011

($Millions)

2011 Actuals

Line No.	Description	Cross-Reference	Mid-Year Capital	Ratio	Prorated Rate Base	Cost Rate %	Return $	Var. Actual to Forecast	Var. %	Working Paper Reference
1	Long-Term Debt	Sch 2.2-T	939.4	53.81%	970.4	5.71%	55.4	(5.9)	-9.7%	
2	Preferred Shares	Sch 2.2-T	160.4	9.19%	165.7	5.92%	9.8	(1.4)	-12.7%	
3	Common Equity	Sch 2.2-T	645.9	37.00%	667.2	10.09%	67.4	4.5	7.2%	**Note 1**
4	**Mid-Year Net Rate Base**	Sch 1.0-T	1,745.7	100.00%	1,803.3	7.35%	132.5	(2.8)		
5	Contribution for Extensions				112.4					
6	No Cost Capital	Sch 2.1-T			10.4					
7	**Mid Year Rate Base**				1,926.2					

2011 Forecast

Line No.	Description	Cross Reference	Mid Year Capital	Deemed Structure	Prorated Rate Base	Cost Rate %	Return $
8	Long-Term Debt	Sch 2.2-T	1,074.4	53.01%	1,028.4	5.96%	61.3
9	Preferred Shares	Sch 2.2-T	202.4	9.99%	193.7	5.80%	11.2
10	Common Equity	Sch 2.2-T	749.9	37.00%	717.8	8.75%	62.8
11	**Mid-Year Net Rate Base**	Sch 1.0-T	2,026.7	100.00%	1,939.9	6.98%	135.4
12	Contribution for Extensions				125.2		
13	No Cost Capital	Sch 2.1-T			9.2		
14	**Mid Year Rate Base**				2,074.2		

Return on Equity Variance

Note 1 2011 Return on Common equity is higher than Forecast mainly due to lower than forecasted O&M, income tax and depreciation expenses.

ALTALINK L.P.
SUMMARY OF RETURN ON RATE BASE
FOR THE YEAR ENDED DECEMBER 31, 2011
($millions)

2011 Actual

Line No.	Description	Cross-Reference	Mid Year Capital	Ratio	Mid Year Prorated Rate Base	Cost Rate %	Return $	Variances	Var. %	Working Paper Reference
			A	B	C	D	E	F	G	H
1	Long-Term Debt	Sch 2.2	1,147.7	61.4%	1,216.7	5.37%	65.3	1.2	1.9%	
2	Short-Term Debt	Sch 2.2	30.0	1.6%	31.8	2.66%	0.8	(1.0)	-53.0%	
3	subtotal		1,177.7	63.0%	1,248.5	5.30%	66.1	0.3	0.4%	
4	Other Costs Associated with Short term Debt	Sch 10					1.8	0.0	0.0%	
5	Preferred Shares	Sch 2.2	-		-		-			
6	Common Equity	Sch 2.2	691.7	37.0%	733.3	9.15%	67.1	3.4	5.3%	
7										
8	**Mid-Year Invested Capital**	Sch 2.1	1,869.3	100.0%	1,981.8	6.81%				
9										
10	**Return on Mid-Year Rate Capital**	Sch 1					135.0	3.6	2.8%	

2011 Approved

Line No.	Description	Cross Reference	Mid Year Capital	Deemed Structure	Mid Year Prorated Rate Base	Cost Rate %	Return $	
15	Long-Term Debt	Sch 2.2	1,147.7	59.6%	1,171.9	5.47%	64.1	
16	Short-Term Debt	Sch 2.2	66.1	3.4%	67.5	2.67%	1.8	
17	subtotal		1,213.8	63.0%	1,239.5	5.31%	65.9	
18	Other Costs Associated with Short term Debt						1.8	
19	Preferred Shares	Sch 2.2	-		-		-	
20	Common Equity	Sch 2.2	712.9	37.0%	728.0	8.75%	63.7	
21								
22	**Mid-Year Invested Capital**	Sch 2.1	1,926.7	100.0%	1,967.4	6.68%		
23								
24	**Return on Mid-Year Rate Capital**	Sch 1					131.4	129.6

Note: Column A represents mid year balance sheet debt and equity and column C represents mid year rate base.

Variance Explanations

Lines # 2 - See variance explanations on Sch 2.3.

Line #6 - Actual return for Common Equity is higher than approved due to lower operating expenses as explained on Schedule 3.

Totals may not add due to rounding

Decision 2011-474

AUC
Alberta Utilities Commission

2011 Generic Cost of Capital

December 8, 2011

The Alberta Utilities Commission
Decision 2011-474: 2011 Generic Cost of Capital
Application No. 1606549
Proceeding ID No. 833

December 8, 2011

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2011 Generic Cost of Capital **Proceeding ID No. 833**

1 Introduction

1. This decision sets out the approved generic return on equity (ROE) for all affected utilities for 2011. It also sets out the Commission's findings with respect to the proposal to re-introduce a formula by which the ROE would be adjusted on an annual basis beyond 2011. The ROE is referred to as "generic" because the approved ROE applies uniformly to all affected utilities. The affected utilities (the Utilities) are:

AltaGas Utilities Inc. (Gas Distribution)
AltaLink L.P. (Electricity Transmission)
ATCO Electric Ltd. (Electricity Distribution and Transmission)
ATCO Gas (Gas Distribution)
ATCO Pipelines (Gas Transmission)
ENMAX Power Corporation (Electricity Distribution and Transmission)
EPCOR Distribution & Transmission Inc. (Electricity Distribution and Transmission)
FortisAlberta Inc. (Electricity Distribution)

2. This decision also sets out individual deemed common equity ratios for each affected utility. Given that the generic ROE is uniformly applied to all of the Utilities, the Commission has accounted for differences in the risk of each utility by adjusting the utility-specific equity ratios.

3. In addition to the above-listed Utilities, all of which participated in this proceeding, there are additional utilities under the Commission's jurisdiction that could be affected by this decision, which were also made aware of, and invited to participate in, this proceeding. As indicated in the notice of this proceeding, the additional utilities include, but are not limited to:

Various investor-owned water utilities regulated by the Commission
EPCOR Energy Alberta Inc. (Regulated Retail Electricity Operations)
ENMAX Energy Corporation (Regulated Retail Electricity Operations)
Direct Energy Regulated Services (Regulated Retail Electricity and Gas Operations)
City of Lethbridge (Electricity Distribution and Transmission)
City of Red Deer (Electricity Distribution and Transmission)
TransAlta Corporation (certain transmission assets)

4. None of these utilities participated in the proceeding. The ROE and debt to equity ratios in this decision do not automatically apply to EPCOR Energy Alberta Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because they are regulated pursuant to the *Regulated Rate Option Regulation* and the *Default Gas Supply Regulation*. The ROE established in this decision will apply to City of Lethbridge Transmission, City of Red Deer Transmission

and TransAlta Corporation's transmission assets. In addition, the Commission has established the equity ratios for each of these utilities. Specific ROEs and capital structures for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding, because the Commission considers these utilities only in response to a complaint. However, the determinations made in this proceeding may be considered in any cost of capital determinations for these utilities under the Commission's jurisdiction, should issues respecting these matters arise.

5. This decision also sets out the Commission's findings with respect to the proposal for a management fee to compensate the utilities for the management of contributed assets. Specifically, the decision considers whether the Commission has jurisdiction to approve a management fee, and whether a management fee is warranted and in the public interest.

6. Finally, this decision addresses the AESO's proposed "Rider I" by which certain customers would be permitted to pay construction contributions in excess of the maximum investment levels approved by the Commission, in equal monthly amounts, over a period of up to 20 years.

2 Procedural summary highlights

7. On September 17, 2010, the Commission initiated this 2011 Generic Cost of Capital (GCOC) Proceeding as ID No. 833 and sought preliminary comments on the scope and schedule for this proceeding.

8. On December 16, 2010, the Commission issued a formal notice of this proceeding and issued a letter detailing the scope of the proceeding. The scope included a full review of the generic ROE and capital structure for each affected utility for 2011, consideration of an annual ROE adjustment formula, or other approach, to be applicable after 2011, and consideration of a management fee on customer contributed assets. Subsequently, Decision 2010-606[1] indicated that consideration of Rider I would be included in the scope of the Generic Cost of Capital Proceeding and this was confirmed in this proceeding in a Commission letter dated January 17, 2011.

9. The division of the Commission assigned to this application is comprised of Commission Member Bill Lyttle; Commission Member Mark Kolesar and Commission Member Moin A. Yahya, who chaired the panel.

10. Notice of this proceeding was published on December 16, 2010, in the four largest newspapers in the province: The Edmonton Journal, the Calgary Herald, the Edmonton Sun, and the Calgary Sun. In addition, the notice was circulated by email to the parties registered for the 2009 GCOC proceeding and to the Commission's general email lists for gas and electric proceedings.

11. The Utilities, after registering individually, worked together and filed a joint submission. The interveners that were active in the proceeding were the Industrial Power Consumers Association of Alberta (IPCAA), the Alberta Electric System Operator (AESO – which

[1] Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Application No. 1605961, Proceeding ID. 530, December 22, 2010.

registered as the Independent System Operator), the Consumers' Coalition of Alberta (CCA), the Office of The Utilities Consumer Advocate (UCA), and the Canadian Association of Petroleum Producers (CAPP).

12. Expert evidence was sponsored by several parties. The Utilities sponsored:

Ms. Kathleen McShane , B.A., M.A, MBA, CFA, President and senior consultant with Foster Associates Inc. of Bethesda, Maryland

Aaron M. Engen, B.A., LLB, MBA, Managing Director, Investment and Corporate Banking, Power & Utilities Group at BMO Capital Markets

CAPP sponsored:

Dr. Laurence Booth, B.Sc., M.A., M.B.A., D.B.A. of the University of Toronto.

The UCA sponsored, as a team:

Dr. Lawrence Kryzanowski, B.A., Ph.D., of Concordia University

Dr. Gordon S. Roberts, B.A., Ph.D., of York University

13. As indicated in the Commission's scope letter of December 16, 2010,[2] for expediency and in order to minimize costs, the complete record of the 2009 GCOC proceeding was incorporated into this proceeding. The complete evidentiary record of this proceeding is filed in the Commission's electronic system under Proceeding ID No. 833. The Commission considers that the close of record for this proceeding was September 9, 2011, which is the date on which reply argument was filed.

14. In reaching the determinations set out within this decision, the Commission 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 Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

3 2011 return on equity

3.1 Introduction

15. The Commission has set out its findings in this section of the decision generally following the same structure as the return on equity section of Decision 2009-216.[3]

16. Parties to the proceeding were asked to address the ROE for 2011 because it had been anticipated that the ROE for 2012 was to be dealt with by way of a formula, or by some other

[2] Exhibit 11.

[3] Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.

method, in the absence of a formula. However, some of the experts also addressed 2012 directly in their ROE evidence.

17. To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was again presented with a significant body of evidence on the tests to be considered when determining the fair ROE, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE estimates based on:

- changes in the financial environment since the 2009 proceeding
- the capital asset pricing model (CAPM)
- the discounted cash flow model (DCF) which was applied to proxy utilities as well as to the equity market overall
- other evidence on comparable investments
- ROE awards by other Canadian regulators
- market price-to-book values
- returns on high grade bonds
- the return expectations from pension and investment managers
- the impact of growth on the required ROE

18. On the basis of this evidence, the Commission was presented with the following recommended ROEs for 2011 and 2012.

Table 1. Summary of ROE recommendations

	Recommended By the Utilities[4] (%)	Recommended by UCA[5] (%)	Recommended by CAPP (%)[6]
2011	10.375	8.3	7.75
2012	10.375	8.4	8.15

19. In this decision, the Commission has established a generic ROE for 2011. In Section 4 dealing with the adoption of a formula for adjusting the ROE beyond 2011, the Commission has determined that it will not adopt a formula at this time and that the ROE for 2012 will be the same as the ROE for 2011.

3.2 Changes in the financial environment since Decision 2009-216

20. Dr. Booth submitted that the Canadian economy was recovering from the financial crisis while the U.S. economy was still weak.[7] He submitted that Canada was two years out of

[4] Exhibit 209, Utilities argument, paragraph 122.
[5] Exhibit 210, UCA argument, paragraphs 149 and 150.
[6] Exhibit 207, CAPP argument, paragraph 114.
[7] Exhibit 207, CAPP argument, page 4.

recession but still had a long way to go.[8] He indicated that the situation in the United States during the financial crisis was "horrendous" but that "now it's less stressful" and that the major impact of the financial crisis has passed. Dr. Booth stated that spreads are still higher in Canada than they were but there is no stress in the financial system in Canada and corporate bond yields have come down.[9] Dr. Booth noted the (then existing) risk that the United States would not increase its debt ceiling.[10]

21. The UCA submitted that there is no dispute that economic conditions have improved since the conclusion of the 2009 GCOC hearing in June 2009. It submitted that 30-year utility bond spreads have declined by 50 basis points since then, that the 2008-2009 crisis is over and has been over for two years, and that we are now in a more typical post-recessionary recovery that is distinguishable from the extraordinary crisis mere months before the 2009 hearing. The UCA also stated that economic parameters have improved significantly and for all practical purposes have "normalized."[11]

22. The UCA proposed that, because there is agreement that conditions have improved directionally since the end of the 2009 proceeding, financial conditions are not a justification for increasing the allowed ROE, as the Utilities would urge.[12]

23. The CCA noted that the intervener and utility experts agreed that capital markets have improved since 2009.[13]

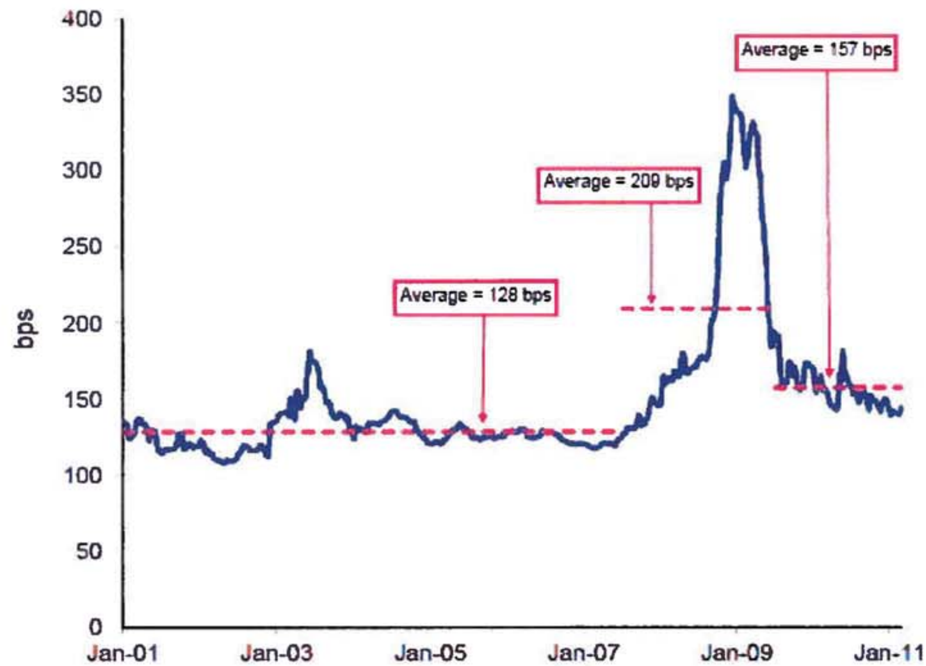
24. The Utilities argued that, although financial markets have stabilized to some degree relative to 2009, risk remains elevated and risk has been re-priced as evidenced by credit spreads.[14] They cited a World Economic Forum publication of January 2011 which had indicated there were ever-greater concerns regarding global risks and "the prospect of rapid contagion through increasingly connected systems and the threat of disastrous impacts."[15]

25. The Utilities noted that Dr. Booth had volunteered that there were significant risks remaining in the global financial system and that his 8.15 per cent recommendation for 2012 was 90 basis points higher than he had recommended in 2009 at the same 4.5 per cent long-term Canada bond yield forecast, in part due to continuing uncertainties.[16]

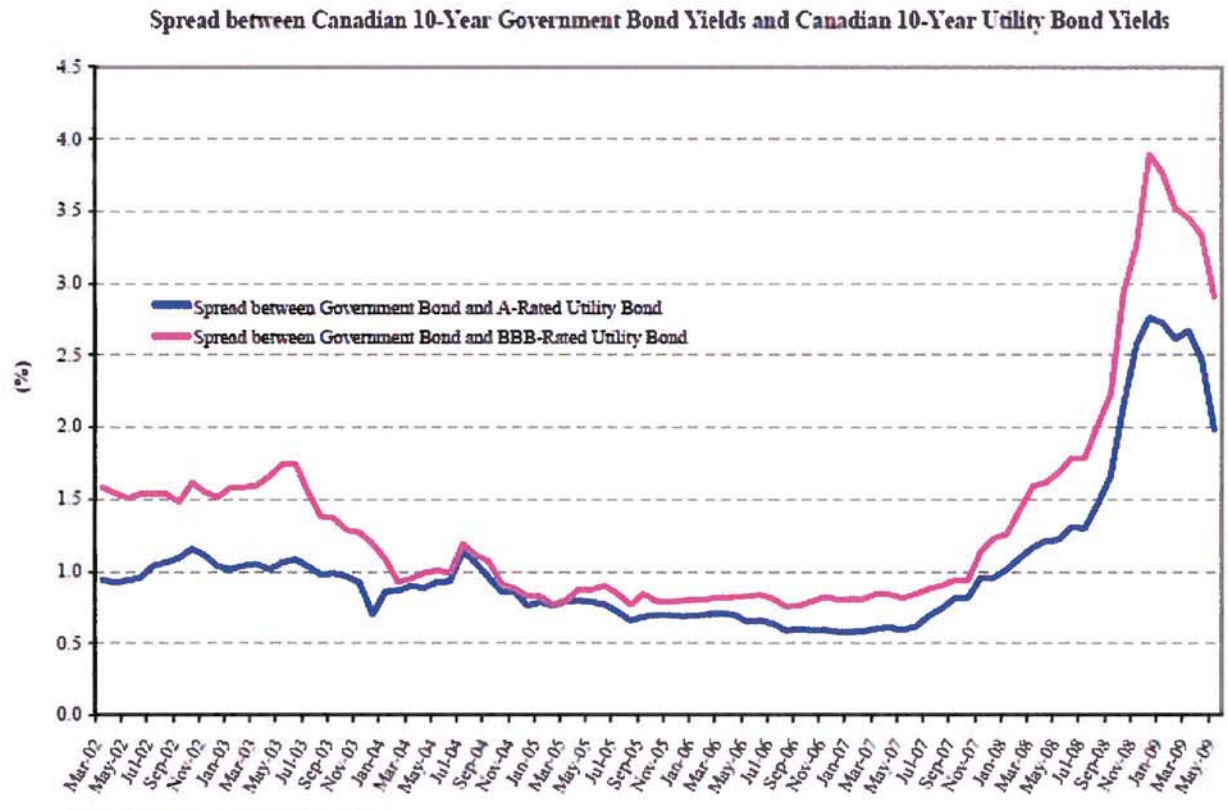
26. The following chart from Exhibit 172 illustrates how the 30-year bond spread for Canadian relatively pure-play regulated utilities had been relatively stable since 2001 but increased sharply (to unprecedented levels) during the financial crisis, and then largely (but not

8 Exhibit 207, CAPP argument, page 6.
9 Exhibit 207, CAPP argument, page 11 and 12.
10 Exhibit 207, CAPP argument, page 13.
11 Exhibit 210, UCA argument, paragraphs 8, 10 and 11.
12 Exhibit 221, UCA reply argument, paragraph 5.
13 Exhibit 211, CCA argument, paragraph 15.
14 Exhibit 208, Utilities argument, paragraph 11.
15 Exhibit 208, Utilities argument, paragraph 25.
16 Exhibit 220, Utilities reply argument, paragraphs 19, 21 and 22.

completely) recovered.



27. For comparison, the Commission notes the following chart from paragraph 301 of Decision 2009-216, which illustrates utility corporate bond spreads prior to the credit crisis and during the credit crisis, up to the time of the 2009 hearing. It indicates that the recovery had begun by the end of the 2009 hearing.



Source: Bloomberg as of May 29, 2009.

28. From the charts above, the Commission finds that corporate bond spreads had begun to recover at the time of the 2009 hearing but had far from fully recovered. The Commission also finds that, in contrast, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

3.3 Capital asset pricing model

29. CAPM is a well-accepted and theoretically-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return. CAPM is based on the principle that investors need to be compensated in two ways: for the time value of money and for risk. In the model, the time value of money is represented by the rate that compensates the investor for placing money in a risk-free investment over a period of time (the risk-free rate). The second part of the model considers risk and estimates the compensation that the investor needs for taking on the risk that the expected return will not be realized. This element of risk is calculated by taking a risk measure (beta) based on the statistical relationship between the historical returns for the investment security relative to the historical returns for the market as a whole, over time. Beta is a risk measure that describes how sensitive the expected return of a security is to the market. Hence, CAPM calculates the expected return for a security as the rate of return on a risk free security plus a risk premium.

30. Evidence to support proposed ROEs based on an application of CAPM was provided by Ms. McShane, Dr. Booth, and Drs. Kryzanowski and Roberts.

31. The following table sets out the recommended individual CAPM components and resulting ROE levels for each of the experts that presented evidence on CAPM.

Table 2. CAPM recommendations

Expert Witness	Risk-free Rate (%)	MERP (%)	Market Return (%)	Beta	Adder	Flotation Allowance (%)	ROE (%)
Dr. Booth 2011	4.10	5.0 to 6.0	9.1 -10.1	0.45 -0.55	0.25 - 0.50	0.50	8.15 (7.5 - 8.8)
Dr. Booth 2012	4.50	5.0 to 6.0	9.5 -10.5	0.45 -0.55	0.25 - 0.50	0.50	7.75 (7.10 - 8.4)
Drs. Kryzanowski & Roberts[17] (At their equity ratio recommendation)	4.20	5.2	9.4	0.52	0.90[18]	0.50	8.3.
Drs. Kryzanowski & Roberts (At higher equity ratios)	4.20	5.2	9.4	0.52		0.50	7.4
Ms. McShane	4.25[19]	7.25[20]	11.5[21]	0.65 – 0.70[22]		1.0[23]	10.0 -10.3[24]

32. Ms. McShane also provided two additional estimates of the equity risk premium. These were developed on a DCF-based method and on historically achieved utility equity risk premiums. The Commission has considered Ms. McShane's DCF results in the DCF section below, rather than considering them in this CAPM section. Similarly, the Commission has considered Ms. McShane's historic utility return data in the comparable investments section below and not in this CAPM section.

33. Dr. Booth confirmed that his explanation of the CAPM provided in the 2009 proceeding remains his view:

> Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major "laws' of finance: the time value of money and the risk value of money…the time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory.[25]

34. Drs. Kryzanowski and Roberts indicated that they had added 90 basis points to their CAPM estimate to be consistent with an A credit rating and a 1.2 price-to-book value ratio, but that the adjustment would not be needed if the Commission adopts higher equity ratios than they

17 Exhibit 210, UCA argument, paragraphs 72-75.
18 Exhibit 210, UCA argument, paragraphs 75 and 78.
19 Exhibit 208, Utilities argument, paragraph 55.
20 Exhibit 86.01, Kathleen McShane opinion, page 55 line 1343.
21 Exhibit 86.01, Kathleen McShane opinion, page 55 line 1344.
22 Exhibit 86.01, Kathleen McShane opinion, page 63, line 1518.
23 Exhibit 86.01, Kathleen McShane opinion, page 79, lines 1934-1938.
24 Exhibit 86.01, Kathleen McShane opinion, page 63, line 1527 and page 79, lines 1934-1938.
25 Exhibit 207, CAPP argument pages 14 and 15 and paragraph 224 of Decision 2009-216.

recommended.[26] For this reason, the Commission included two CAPM ROE recommendations for Drs. Kryzanowski and Roberts in the table above. The Utilities submitted that Drs. Kryzanowski and Roberts' CAPM estimate was, by their own admission, insufficient for an A credit rating until they had made a credit metric adjustment.[27]

35. In considering the evidence on CAPM, the Commission reviewed the proposals on the individual components of CAPM, as well as each party's overall ROE estimate based on the CAPM approach. Each CAPM component, and the overall resulting CAPM estimates of ROE, are addressed below.

3.3.1 Risk-free rate

36. The CAPM analysis starts from a forecast of the risk-free rate.

37. Ms. McShane, on behalf of the Utilities, estimated the 2011-2012 average long-term Canada bond yield at 4.25 per cent.[28] This was an average of her 4.0 per cent forecast for 2011, based on the January 2011 Consensus Economics forecast and the December 2010 spread between the 30-year and 10-year Canada bonds, and her 4.5 per cent estimate for 2012 based on the most recent forecasts from major Canadian banks.[29]

38. Dr. Booth forecast a risk-free rate of 4.50 per cent for 2012, indicating that this was somewhat higher than his 2009 forecast, given that Canada is further along in its recovery. Dr. Booth had considered the Consensus Economics forecast, as well as that of the Royal Bank of Canada, and he discussed the views of the Bank of Canada. He forecast a rate of 4.10 per cent for 2011 but supported the use of 4.50 per cent for both 2011 and 2012.[30]

39. Drs. Kryzanowski and Roberts forecast the 30-year bond yield at 4.20 per cent for 2011 based on the Consensus Economics forecast and recently observed spreads between the 30-year and 10-year Canada bonds; adding 15 basis points for more recent movements in the 10-year yield.[31]

40. The UCA noted that all of the experts had applied judgment to arrive at a risk free rate similar to 2009, even though actual long-term Canada bond rates and the Consensus Economics forecast used in the National Energy Board's formula indicated a reduction of 60 basis points since 2009.[32]

41. The Commission notes that the latest available Consensus Economics forecast on the record, from July 2011, forecast a 10-year Government of Canada bond rate for October 2011 of 3.3 per cent and for July 2012 of 3.8 per cent.[33] Adding 50 basis points for the spread between the 10-year and the 30-year bond forecasts results in a 30-year forecast of 3.8 per cent for October 2011 and 4.3 per cent for July 2012.

26 Exhibit 210, UCA argument, paragraphs 75 and 78.
27 Exhibit 208, Utilities argument, paragraphs 48 -51.
28 Exhibit 208, Utilities argument, paragraph 55.
29 Exhibit 86.01, Kathleen McShane opinion, page 52, lines 1094 to 1104.
30 Exhibit 207, CAPP argument, page 16.
31 Exhibit 210, UCA argument, paragraph 25.
32 Exhibit 221, UCA reply argument, paragraph 34.
33 Exhibit 204.01.

42. The July 2011 Consensus Economics forecast, referenced above, also indicated that the actual 10-year Government of Canada bond yield in July 2011 was 2.9 per cent. At the time of the 2009 hearing, the actual 10-year Canada bond interest yield was 3.5 per cent.[34] Therefore, the Commission notes that the 10-year Canada bond yield declined 60 basis points from the 2009 hearing to the 2011 hearing.

43. The Consensus Economics forecast has traditionally been used by the Commission and its predecessor to estimate the risk free rate. In 2009, the Commission found that a risk free rate in the range of 4.13 per cent to 4.50 per cent was reasonable, based on the Consensus Economics forecast at that time. Based on the Consensus Economics forecasts and the July 2011 actual 10-year interest rate of 2.9 per cent, on the record of this proceeding, the Commission considers that a long-term bond yield forecast of 3.4 per cent to 3.8 per cent for 2011 is reasonable, considering the current volatility in rates and the 60 basis point decline since 2009.

3.3.2 Market equity risk premium

44. The next element of the CAPM analysis is the market equity risk premium (MERP). Parties recommended a number of market equity risk premiums.

45. The Utilities argued that an arithmetic average market equity risk premium should continue to be used, rather than the lower geometric average.[35] Ms. McShane submitted that arithmetic average returns have been 1.7 per cent higher than the geometric average in Canada since 1924 and 2.0 per cent higher in the U.S. since 1926. She submitted that the arithmetic average was 1.3 per cent and 1.5 per cent higher than the geometric average for Canada and the U.S., respectively, in the post war period.[36]

46. Ms. McShane submitted that historic risk premium data should not be used without considering that today's environment may be different.[37] In support of this, she relied on her analysis which, she submitted, demonstrated that equity returns and risk premiums have tended to be higher when (as now) bond interest rates are low.[38] She also submitted that her analysis demonstrated that equity returns have been higher when (as now) inflation is low.[39] The Utilities argued that Drs. Kryzanowski and Roberts' proposed adjustment formula implicitly suggests that the equity market return does not decline with lower interest rates, which supports the Utilities' position.[40]

47. Dr. Booth estimated that the market equity risk premium is five per cent and indicated that a range of 5.0 to 6.0 per cent was reasonable.[41]

48. The UCA submitted that the use of a longer historical period can improve the accuracy of the market equity risk premium estimate in a statistical sense but may introduce errors because historical conditions may differ from today. In particular, the UCA submitted that trading costs and impediments to foreign diversification may explain higher historical risk premiums.

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34 Exhibit 367.02 of Proceeding 85, 2009 Generic Cost of Capital.
35 Exhibit 208, Utilities argument, paragraphs 57 and 58.
36 Exhibit 86.01, Kathleen McShane opinion, page 52 lines 1269-1271.
37 Exhibit 86.01, Kathleen McShane opinion , lines 1083-1085.
38 Exhibit 86.01, Kathleen McShane opinion, page 49, Table 9.
39 Exhibit 86.01, Kathleen McShane opinion, page 54, Table 12.
40 Exhibit 219, Utilities reply argument, paragraph 38.
41 Exhibit 207, CAPP argument, page 17.

Drs. Kryzanowski and Roberts estimated the market equity risk premium at 5.2 per cent using a weighting of 75 per cent geometric average and 25 per cent arithmetic average and considering various historical periods in both Canada and the U.S.[42]

49. Drs. Kryzanowski and Roberts submitted that Ms. McShane's evidence failed to test whether this inverse relationship had been expected by investors, that she had not provided tests of significance and that she failed to adjust for unique past events including wage and price controls.[43] Drs. Kryzanowski and Roberts submitted that the most damaging argument against Ms. McShane's results were that they were inconsistent with the return expectations of investment professionals.[44] However, the Commission notes that the "different results" that Drs. Kryzanowski and Roberts noted, based on geometric returns, still indicated equity returns that were inversely correlated to inflation.[45]

50. Ms. McShane estimated that the market risk premium, at her forecast 4.25 per cent long-term Canada bond yield, was 6.5 per cent to 8.0 per cent or, using the mid-point, approximately 7.25 per cent.[46]

51. The Utilities submitted that equity market returns have not declined, but that achieved bond returns have increased as interest rates declined. They submitted that market risk premiums have not declined when measured against the bond income returns which, they argued, is the risk-free rate which should be used in the CAPM since it is the risk free portion of bond returns.[47] The Commission notes that Ms. McShane's equity market risk premium was based on the premium over bond yields, rather than over bond total returns. The Commission also notes that, if the market equity risk premium is constant, then equity returns would also have been impacted by lower interest rates. For this reason, Ms. McShane's proposal appears to compare a return on bonds which excludes capital gains caused by lower interest rates, to a return on equities that may include capital gains directly caused by lower interest rates. This does not appear to be consistent. The Commission is not convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, which is the traditional approach.

52. The Commission notes that long-term average data on achieved historical market risk premiums are usually used to estimate the required market equity risk premium going forward. However, in this proceeding, Ms. McShane has provided evidence that the market equity risk premium varies inversely with interest rates and inflation, and the UCA noted that using data from longer periods of time could introduce errors if historical conditions differ from those of today. For these reasons, the Commission is not prepared to use the long-term historical market risk premium as the applicable market equity risk premium for 2011, given that the risk free rate is far below its long-term historical average. The Commission also considered ongoing arguments about whether the geometric or the arithmetic average risk premium should be used, the observation that realized equity risk premiums were not necessarily the risk premiums that investors had expected, and the possibility that historic realized premiums are not necessarily reflective of future expectations.

42 Exhibit 210, UCA argument, paragraphs 27 and 30.
43 Exhibit, 142.02, rebuttal evidence of UCA, paragraphs 27 to 37.
44 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 38.
45 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 34.
46 Exhibit 86.01, Kathleen McShane opinion, page 55, lines 1341-1342.
47 Exhibit 220, Utilities reply argument, paragraphs 34 and 35.

53. The Commission has explored the relationship, discussed by Dr. Booth, of the market return, the utility return and the market equity risk premium implied by ROE formulas that allow the utility ROE to change with interest rates, as set out in tables 3 and 4 below.

Table 3. Formula results when utility ROE changes at 75 per cent of change in risk free rate and beta is 0.55

Risk free rate	Beta	Implied market risk premium	Implied market return	Formula utility return	Note
5.0%	**0.55**	**5.00%**	**10.00%**	**7.75%**	**Initial ROE**
6.0%	0.55	4.55%	10.55%	8.50%	Formula Result
7.0%	0.55	4.09%	11.09%	9.25%	Formula Result
4.0%	0.55	5.45%	9.45%	7.00%	Formula Result
3.0%	0.55	5.91%	8.91%	6.25%	Formula Result

Source: Commission staff calculations based on Dr. Booth's evidence. (Exhibit 78.02, pages 72-73).

Table 4. Formula results when utility ROE changes at 50 per cent of change in risk free rate and beta is 0.50

Risk free rate	Beta	Implied market risk premium	Implied market return	Formula utility return	Note
5.0%	**0.50**	**6.00%**	**11.00%**	**8.00%**	**Initial ROE**
6.0%	0.50	5.00%	11.00%	8.50%	Formula Result
7.0%	0.50	4.00%	11.00%	9.00%	Formula Result
4.0%	0.50	7.00%	11.00%	7.50%	Formula Result
3.0%	0.50	8.00%	11.00%	7.00%	Formula Result

Source: Commission staff calculations based on Dr. Booth's evidence. (Exhibit 78.02, pages 72-73).

54. The Commission notes that the ROE adjustment formula that was approved by the Commission's predecessor allowed ROE to fluctuate at 75 per cent of the change in interest rates. Table 3 above illustrates that, at a beta of 0.55 (as used in the 2004 Generic Cost of Capital Decision), the market risk premium implicitly changed inversely at 45 per cent of the change in interest rates. The use of the formula implies that the market risk premium is not constant.

55. The ROE adjustment formula proposed in this proceeding, based on the formula adopted by the Ontario Energy Board (OEB), would allow the ROE to change at 50 per cent of the change in interest rates. As Dr. Booth pointed out, this implies that with a beta of 0.50, and assuming no change in bond spreads, the market equity risk premium changes directly with the change in interest rates and that the market return is constant and does not change with interest rates. The Commission notes that, in sharp contrast to this, a formula based on a constant market equity risk premium would allow the Utility ROE to change at 100 per cent of the change in interest rates and would imply that the market equity return, far from being constant, would change at 100 per cent of the change in interest rates.

56. Based on the above observations about the implicit relationship of the market risk premium to interest rates that is embedded in the formulas that parties support, it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates.

57. The Commission understands that actual long-term interest rates are near historic lows. At the Commission's estimated risk-free rate of 3.4 per cent to 3.8 per cent, the 30-year Government of Canada bond yield would be at the lower end of its historic range. In this circumstance, the Commission considers that it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value.

58. Considering all of the above, the Commission finds that the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates. The Commission accepts that the market equity risk premium today may reasonably be as high as the 7.25 per cent mid-point of Ms. McShane's estimate.

59. The market equity risk premium from each expert's CAPM forecast is provided in Table 2 above. These range from 5.0 to 7.25 per cent. The Commission finds that a reasonable range for the market equity risk premium is 5.0 per cent to 7.25 per cent.

3.3.3 Beta

60. The next element of the CAPM analysis is the beta. Beta is a statistical measure describing the relationship of a stock's return with that of the stock market as a whole. In the Commission's view, the proper beta to use is that which represents the relative risk of stand-alone Canadian utilities. Past data (with or without adjustment) is usually used to estimate the reasonably expected beta going forward.

61. Ms. McShane used an adjusted beta to account for empirical studies that show that low beta stock returns would otherwise be under-estimated. Ms. McShane adjusted beta based on her own analysis of the adjustment required to explain historically achieved Canadian regulated company returns.[48] The Utilities proposed a beta in the range of 0.65 to 0.70.

62. The Utilities noted Ms. McShane's position that total risk, and not just diversifiable risk, should be considered for an undiversified investor, such as a utility investing in hard assets.[49] The Commission does not agree. The Commission's objective is to establish a market ROE for an investment of equivalent risk, held in a diversified market portfolio, because this emulates the conditions under which utilities raise equity capital.

63. The Utilities also noted that Dr. Fernandez (whose work had been cited by Dr. Booth) had provided evidence that the CAPM does not work and had concluded that historical betas are useless to estimate the expected return of companies.[50] However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

64. The Utilities submitted that low risk utilities may not necessarily require a lower return than the overall market, when their higher financial leverage and risk is considered.[51] In the Commission's view, while a utility typically has higher financial leverage than a typical company on the stock market, it also has a correspondingly higher capacity for leverage due to its lower business risk. In the Commission's view, estimates of beta for utilities are estimates of utility risk relative to the market and already take into account the higher leverage of utilities.

48 Exhibit 208, Utilities argument, paragraph 66.
49 Exhibit 220, Utilities reply argument, paragraph 39.
50 Exhibit 220, Utilities reply argument, paragraph 40.
51 Exhibit 220, Utilities reply argument, paragraph 61.

65. Dr. Booth estimated that the Canadian stand-alone utility beta continues to be 0.45 to 0.55, the same range as he estimated in 2009. Dr. Booth based this conclusion on the performance of Canadian utility holding companies during the credit crisis, and the actual betas of low-risk U.S. utilities.[52]

66. Drs. Kryzanowski and Roberts submitted that a reasonable beta is 0.52. This was unchanged from their 2009 estimate and was based on observed betas.[53]

67. In 2009, the Commission found that a reasonable range for beta was 0.50 per cent to 0.63 per cent. Based on the 2011 evidence, the Commission is not persuaded to materially alter its finding from 2009. The Commission finds that a reasonable beta estimate is 0.50 per cent to 0.65 per cent.

3.3.4 Flotation allowance

68. The final element of the CAPM analysis is the flotation allowance. The parties all agreed that a flotation allowance is normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution. Historically, the Commission and its predecessors have allowed 0.50 per cent additional return on equity to account for the costs of flotation and to better ensure that the investor can expect to receive at least the required return.

69. In the Commission's view, the flotation allowance also applies, for the same reasons, to the DCF method and all other estimates of the investor's required return. The reason for this is that, if a utility has flotation or issuing costs which it cannot claim as regulated expenses, then the utility needs to earn more than the investors required return in order to cover these added costs.

70. Dr. Booth continued to apply the traditional 0.50 per cent flotation allowance.[54]

71. Drs. Kryzanowski and Roberts added the standard and traditional 50 basis points allowance. They explained that only 10 basis points were related to cost but added 40 basis points for flexibility based on common regulatory practice in Canada.[55]

72. Ms. McShane, for the Utilities, recommended a higher flotation allowance of 100 basis points to recognise the difference between the market value capital structures of proxy companies and the book value capital structures used by the Commission.[56]

73. The Utilities noted Ms. McShane's evidence that the DCF and equity risk premium models represent conceptually different ways in which investors may approach estimating the return they require on the market value of an equity investment. She had submitted that, while the DCF and risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the capital invested in the book value of the

52 Exhibit 78, evidence of Laurence D. Booth, pages 56 and 57.
53 Exhibit 210, UCA argument, paragraph 54.
54 Exhibit 207, CAPP argument, page 19.
55 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 103.
56 Exhibit 209, Utilities argument, paragraph 83.

assets included in rate base. She submitted that the determination of a fair return on book equity needs to recognize that distinction.[57]

74. The UCA submitted that the Commission should continue to apply market returns to a book value rate structure in accordance with the 2004 Generic Cost of Capital Decision.[58]

75. The Commission does not agree with Ms. McShane's argument for increasing the flotation allowance above the historically allowed 0.50 per cent. Arguments that a market return should be applied to a market value based rate base, rather than a book value rate base, are circular since the market value is clearly dependent on the awarded return.

76. Accordingly, the Commission finds that the usual regulatory convention of awarding a flotation allowance of 0.50 per cent continues to be reasonable.

3.3.5 The Commission's resulting CAPM estimate

77. Applying its findings on the individual components of CAPM, the Commission calculated a range of CAPM ROE results for the required equity return for investors in stand-alone Canadian utilities of 6.4 per cent to 9.0 per cent.

Table 5. Commission's CAPM findings

Commission's CAPM Findings	Risk-free Rate	MERP	Market Return	Beta	Flotation Allowance	CAPM ROE
2011	3.4 % - 3.8%	5.0 - 7.25	8.40% -11.05%	0.50 -0.65	0.50	6.4% - 9.0%

3.4 Discounted cash flow model

78. The discounted cash flow model is used to estimate the cost of a company's common equity based on the current dividend yield of the company's shares plus the expected future dividend growth rates. The DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price.

79. Parties applied the DCF method to both sample utility companies and to the market as a whole.

80. Ms. McShane, on behalf of the Utilities, provided a number of DCF estimates. She included DCF results for a sample of U.S. low-risk utilities as well as a sample of five Canadian utilities. These results used both analyst growth estimates and sustainable growth estimates (a calculation of growth based on ROE times the portion of earnings retained). She also provided both average and median results. The Commission focused on the average results because the median figures were internally inconsistent, given that the median dividend plus the median growth did not equal the median DCF result shown. Ms. McShane's DCF estimates were in the range of 8.5 to 9.5 per cent.[59]

81. In arguing for additional weight to be placed on DCF results, Ms. McShane compared it to the CAPM test. She submitted that the DCF test is a positive model that measures the expected returns actually available to investors. In contrast, she stated that the CAPM measures the cost of

57 Exhibit 210, UCA argument, paragraph 84.
58 Exhibit 210, UCA argument, paragraph 85.
59 Exhibit 86.01, Kathleen McShane opinion, Schedules 16 and 17.

capital indirectly. In her view, DCF measures "what is" while CAPM estimates the required return on the market value of common stock on a "what should be" basis.[60]

82. Drs. Kryzanowski and Roberts applied the DCF method to the market as a whole and arrived at a return estimate for the overall equity market of 8.0 per cent.[61]

83. Dr. Booth stated that the DCF estimate of ROE for the Standard & Poor's (S&P) 500 utilities sub-index was 8.98 per cent.[62] Dr. Booth applied the DCF method to the Canadian equity market as a whole and found it indicated a required investor return of 8.2 to 8.4 per cent. This did not include a flotation allowance. Dr. Booth indicated that this represented a minor under-estimation due to current recession conditions and proposed that growth coming out of the recession would be higher.[63]

84. The following table sets out the individual DCF components and resulting ROE levels proposed by each of the parties that presented evidence on the DCF model.

60 Exhibit 86.01, Kathleen McShane opinion, pages 75 and 43.
61 Exhibit 210, UCA argument, paragraph 96.
62 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 CAPP Argument, page 20.
63 Exhibit 78, evidence of Laurence D. Booth, paragraph 152.

Table 6. Summary of DCF estimates

Expert Witness	Dividend yield (%)	Stage 1 growth rate (%)	Stage 2 growth rate (%)	Final growth rate (%)	Investor required ROE (%)
DCF Applied to the Equity Market Overall					
Dr. Booth overall Canadian Market[64]	2.45			5.6 – 5.83	8.2 – 8.4
Drs. Kryzanowski and Roberts Toronto Stock Index using GDP estimates[65]	2.62 or 2.74			4.3, 4.83 and 5.20	7.09, 7.5, and 7.94
Drs. Kryzanowski and Roberts Toronto Stock Index using forecasts of pre-tax corporate earnings[66]	2.80				9.02, multi-stage growth 10.05 single stage growth
DCF Applied to Sample Utilities					
Dr. Booth S&P 500 utilities sub-index	5.01[67]			3.78[68]	8.98[69]
Ms. McShane U.S. utilities sample , average analyst constant growth estimates[70]	4.2			4.6	8.8
Ms. McShane U.S. utilities sample , calculated average sustainable growth[71]	4.2			4.9	9.0
Ms. McShane U.S. utilities sample , average three stage growth estimates (GDP growth for final stage) [72]	4.2	4.6	4.8	4.9	8.9
McShane Canadian utilities sample average analyst constant growth estimates[73]	3.8			5.7	9.5
McShane Canadian utilities sample average three stage growth estimates (GDP growth for final stage)[74]	3.8	5.7	5.1	4.6	8.5

64 Exhibit 78, evidence of Laurence D. Booth, paragraph 152.

65 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.4a, pages 38 to 39.

66 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.4a, pages 38 to 39.

67 Exhibit 78, evidence of Laurence D. Booth, paragraph 153.

68 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 (which incorrectly indicated 3.48 per cent) and Schedule 4 which indicated 3.78 per cent.

69 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 (8.98 per cent is from 1.0378 times 1.0501).

70 Exhibit 86.01, Kathleen McShane opinion, Schedule 16.

71 Exhibit 86.01, Kathleen McShane opinion, Schedule 17.

72 Exhibit 86.01, Kathleen McShane opinion, Schedule 18.

73 Exhibit 86.01, Kathleen McShane opinion, Schedule 19.

74 Exhibit 86.01, Kathleen McShane opinion, Schedule 20.

85. In 2009, the Commission rejected the use of long-term or terminal growth rates for utilities that exceed estimates of nominal dollar GDP growth. For 2011, there was no indication that the terminal growth rate forecasts exceeded reasonable estimates of nominal GDP growth.

86. In 2009, the Commission expressed concern about the potential upward bias in analysts' growth estimates.[75] However, Ms. McShane argued that, as long as investors believe the optimistic forecast, they would price the securities lower (resulting in a lower dividend yield) and the DCF test would still be an unbiased estimate of investor required returns. She indicated that this proposition had been successfully tested and described three tests, including the fact that such growth estimates have averaged less than GDP growth.[76] In the Commission's view, this line of reasoning does not resolve the issue because there is no evidence that investors believe optimistic forecasts. Therefore, the Commission remains concerned with the potential upward bias in analysts' growth estimates.

87. In 2009, the Commission also expressed concern about using proxy companies in a DCF analysis that are utility holding companies engaged in significant unregulated activities.[77] The Commission notes that Ms. McShane's Canadian sample consists of Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc. and TransCanada Corp. Of these, the Commission continues to consider only Emera Inc. and Fortis Inc. to be relatively free of unregulated activities. The Commission notes that the DCF results were 9.3 per cent for Emera Inc., using the three stage estimate, and 8.8 per cent for Fortis Inc., also using the three stage estimate.

88. The results above appear to suggest that investors expect a return of about 9.0 per cent on utility investments, assuming investors agree with analysts' growth forecasts. The Commission also notes that the DCF applied to the overall market suggested returns in the range of 7.1 to 10.1 per cent.

89. As explained above, the Commission considers that the DCF results should be adjusted to include flotation costs. As with the CAPM analysis, the Commission has adjusted the DCF results to include a 0.50 per cent flotation allowance

90. Overall, the Commission finds the 2011 results of the DCF analyses presented in the proceeding suggest a range of allowed ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming that the equity ratio has been set to target a credit rating in the A range. However, as noted above, the Commission remains concerned about the potential impact of optimistic growth forecasts in this result.

3.5 Market returns on comparable investments

91. In AUC-ENGEN-09 (Exhibit 138), Mr. Engen provided data for certain Canadian energy infrastructure companies and included the price/earnings (P/E) ratios, the dividend yield, the price-to-book ratios and the ROEs. The median company in this group had a P/E ratio of 21.1, which equates to an earnings yield of 4.7 per cent. The median dividend yield was 5.2 per cent, which, because it is higher than the earnings yield, indicates that more than 100 per cent of the accounting earnings were being paid out, for the median company. The median price-to-book ratio was 2.1 times and the median ROE was 10.5 per cent. The Commission recognizes that

75 Decision 2009-216, paragraph 269.

76 Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.

77 Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.

infrastructure companies may also be able to pay out cash flows from depreciation and future income taxes that are in excess of earnings (at least temporarily, until long-lived assets need to be replaced).

92. The UCA submitted that Mr. Engen's evidence on certain Canadian energy infrastructure firms showed price-to-book values well in excess of 1.0, with the median and mean P/E ratios over 20, implying an earnings yield of five per cent. The UCA acknowledged that this did not account for growth and was not necessarily indicative of an appropriate allowed ROE, but submitted that it did indicate that investors in these shares were content with the firms having earnings yields in the range of five to six per cent of their market values which, it submitted, suggests that the required returns for utility investors are nowhere near the levels proposed by Ms. McShane.[78]

93. In the Commission's view, it is possible that part of the reason for the high P/E ratios is that, similar to the case with bonds, the higher prices and lower earnings and cash yields are an indication that the market required return has fallen. Another possibility is that investors expect to ultimately receive substantially more than the median earnings yield of 4.7 per cent and more than the median cash yield of 5.6 per cent, due to growth. However, with more than 100 per cent of the earnings being paid out in dividends, the sustainable growth formula (growth equals ROE times the proportion of earnings retained) would suggest that there will be minimal or no growth. Investors may still have legitimate expectations for growth, perhaps based on past experience. The sustainable growth formula assumes a constant ROE and does not take into account the ability to issue new shares and invest that money on an accretive basis. It also does not account for the fact that these infrastructure companies (with long-lived assets) may be able to invest some of the depreciation cash flows and future income tax cash flows to fund growth. Ultimately, however, one would assume that depreciation cash flows will be needed to replace existing assets.

94. In the Commission's view, the data provided by Mr. Engen on Canadian infrastructure companies does not provide much support for the case that investors should reasonably expect to earn double digit returns in these investments. It would require growth in the range of 4.8 per cent annually (added to the dividend yield of 5.2 per cent) to arrive at a 10 per cent expected return. With more than 100 per cent of the earnings being paid out as dividends, it is not clear where earnings growth beyond the rate of inflation would come from.

95. Overall, the Commission finds that the evidence is inconclusive on the return investors expect on these infrastructure companies, and there is insufficient evidence that these returns are sufficiently comparable to the utility investments at issue in this proceeding.

3.5.1 Historic returns

96. In her evidence, Ms. McShane examined the historic returns for utilities. According to Ms. McShane, the historical average utility return, in both Canada and the U.S., has clustered in the 11.0 to 12.0 per cent range. She submitted that investors tend to base their expectations on experienced returns and that there was no long-term upward or downward trend. She submitted that the utility returns had varied by approximately 50 per cent of the change in long-term government bond yields.

[78] Exhibit 210, UCA argument, paragraph 103.

97. Ms. McShane also used this historical data on the experienced returns of utilities to provide an additional equity risk premium estimate derived from the observed equity risk premiums achieved by utilities. This resulted in an equity risk premium of 6.25 to 6.5 per cent. At Ms. McShane's forecast Canada bond yield of 4.25 per cent, the indicated utility cost of equity was approximately 10.50 to 10.75 per cent or 11.5 to 11.75 per cent after adding her recommended 1.0 per cent for flotation.

98. The UCA noted that Ms. McShane had provided evidence indicating that utility investors have made returns that are higher than the overall market and stated that, at best, this was evidence that regulators have over-estimated the risk-adjusted cost of equity (and thereby provided a return that is too high).[79]

99. The Commission agrees with the UCA that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. The Commission finds that the evidence on historic returns is inconclusive with respect to the return investors expect on comparable investments.

3.6 Returns awarded by other regulators

100. The Utilities submitted that the mean and median equity returns allowed by Canadian utility regulators, excluding Alberta, are 9.62 per cent and 9.66 per cent, respectively. The Utilities noted that some of these returns involved negotiated settlements but they argued that the results from a range of negotiated settlements provide insight as to reasonable returns.[80] The Utilities submitted that this comparison indicates that the current ROE of 9.0 per cent is too low.

101. The Commission notes that these awarded returns range from 8.38 per cent for Newfoundland Power for 2011 to 10.15 per cent for Pacific Northern Gas–West for 2011. The Commission also notes that these awarded returns would have pre-dated the drop in interest rates that occurred in August 2011 and may have reflected premiums for the 2008-2009 credit crisis.

102. The Commission also gives no weight to the equity returns arising from negotiated settlements. The Commission recognizes that, in a negotiated settlement, there are various trade-offs to which parties have agreed that can skew the awarded ROE.

103. Accordingly, the Commission gives no weight to the returns awarded by other regulators and included on the record of this proceeding.

3.7 Price-to-book ratios

104. An equity price-to-book ratio (also called market-to-book ratio) is calculated by dividing the current market price of a stock by its current book value per share. It is often used to compare a stock's market value to its book value. There was considerable debate during the proceeding as to the relevance, if any, of price-to-book ratios.

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[79] Exhibit 210, UCA argument, paragraphs 104 and 105.

[80] Exhibit 209, Utilities argument, paragraphs 101-103.

105. The Utilities provided a variety of arguments as to why price-to-book ratios of utility holding company shares and those derived from the acquisitions of utilities are not indicative of required returns or the cost of capital.[81]

106. In regards to the price-to-book value of the 2001 AltaLink transaction, the Utilities referred to AUC-ENGEN-07. In that response, Mr. Engen indicated that the price-to-book value at the time of the purchase was 1.93. He also indicated that subsequent additional investments by AltaLink (which are made at book value) have reduced the ratio to 1.26. However, the Commission notes that this 1.26 estimate is not calculated as the current value of AltaLink divided by its current book equity and does not appear to be a relevant figure.

107. In his rebuttal evidence, Dr. Booth provided an appendix of basic financial relationships and stated "[i]f a Board then accepted a high market-to-book ratio in any way, it is implicitly indicating that it is awarding an unfair allowed ROE and is being derelict in the exercise of its statutory responsibilities." He noted that an exception is to allow a ratio slightly above 1.0 to prevent dilution on a share issue.[82]

108. Dr. Booth stated that the observed price-to-book ratios indicate allowed returns have generally been higher than the fair return. CAPP submitted that the bidding war for Central Vermont Power resulted in an equity price-to-book ratio at or above 2.0. CAPP also noted that AltaLink itself indicated a price-to-book ratio of 1.58 regarding the 2011 sale of a portion of AltaLink.[83]

109. In their evidence, Drs. Kryzanowski and Roberts indicated the ROE for Fortis Inc. (which they indicated was the only Canadian relatively pure-play utility, considered by the Commission in 2009, that trades on the market) is generous because Fortis Inc.'s price-to-book ratio is well above 1.0, despite substantial intangible assets (goodwill), indicating the ROE is above the cost of equity.[84] They submitted that high utility price-to-book values in the U.S. mean the utility returns on market value have been single digit. They also submitted that the recent AltaLink transaction, involving the purchase by the SNC-Lavalin Group Inc. of the minority interest in AltaLink, represents a low ROE for the purchaser.

110. The UCA submitted that there did not appear to be any dispute that, in theory, a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. The UCA also submitted that another fact that did not seem to be in dispute was that the actual market-to-book ratios for utility shares, and in utility purchase transactions, are almost always considerably higher than 1.0.[85] The UCA submitted that the fact that the observed market-to-book ratios are so significantly above 1.0 strongly suggests that prevailing allowed returns are too high, and probably by a considerable amount.[86]

111. The UCA submitted that utility shares trade in the market at a value almost twice the book value of utility assets.[87] The UCA noted that Drs. Kryzanowski and Roberts had estimated the price-to-book value of the 2011 AltaLink transaction to be 1.95, with goodwill included in

81 Exhibit 209, Utilities argument, paragraphs 106-113.
82 Exhibit 145.01, update and rebuttal evidence of Laurence D. Booth, page 44.
83 Exhibit 207, CAPP argument, paragraphs 57 and 58.
84 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 15.
85 Exhibit 210, UCA argument, paragraphs 108 and 109.
86 Exhibit 210, UCA argument, paragraph 119.
87 Exhibit 210, UCA reply argument, paragraph 53.

the book value, and 3.39 with goodwill excluded.[88] The Commission considers that the relevant price-to-book value for a pure-play regulated utility with no unregulated business is the price to the book value of the portion of rate base supported by equity, which would exclude goodwill from book value since goodwill is not allowed in rate base.

112. Decision 2009-216 stated that:

> The Commission considers that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios for utility holding companies.
>
> ...
>
> The (equity) price-to-book ratio for the 2007 Fortis acquisition of Teresen Inc. was discussed on the record of the proceeding as a potential indicator of the price-to-book ratio for a stand-alone utility. However, there was considerable disagreement as to the correct calculation of the price-to-book value for this transaction. Price-to-book values in the range of 1.27 to 3.99 were provided. Despite the lack of agreement with respect to the exact calculation, the evidence is that the price paid for Teresen Inc. was at a price-to-book ratio above 1.2. It appears therefore that the awarded return for Teresen was at least fair, at the time of the transaction. However, there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009.[89] (footnotes omitted)

113. The Commission notes the evidence that pure-play regulated Canadian utility assets have historically been valued at equity price-to-book value ratios significantly above 1.0, including the 2011 AltaLink transaction, the 2007 Fortis Inc. purchase of Terasen Inc., the 2004 Fortis Inc. purchase of Aquila (referenced in Decision 2004-052[90]) and AltaLink's 2001 purchase of the transmission assets of TransAlta.

114. In Decision 2009-216, the Commission indicated it could not rely on such transactions, specifically the 2007 Terasen transaction, as being indicative of a fair return for 2009. The situation in 2009 was that, during the credit crisis, stock markets declined substantially, and it was clear that the higher levels of price to book ratios observed in the above transactions, would have declined during the credit crisis. The subsequent 2011 AltaLink transaction following the recovery in stock market prices may be evidence that pure-play regulated Canadian utilities are once again valued at high price-to-book ratios. The question then becomes; do high price-to-book ratios indicate that regulated returns have been above the market required level?

115. The Commission's predecessor indicated in Decision 2004-052 that strategic factors, growth and geographic diversification might explain the payment of a premium. There was some debate in this proceeding on the reasons why investors have been willing to pay significant premiums to purchase pure-play regulated utility assets.

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88 Exhibit 210, UCA argument, paragraph 120.

89 Decision 2009-216, paragraphs 295 and 297.

90 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, July 2, 2004.

116. Mr. Engen proposed that the opportunity for cross-border purchasers to deduct the same interest in two countries may explain the premiums. Dr. Booth noted, and the Commission agrees, that in the transactions referenced above there were no cross-border purchasers involved. Mr. Engen proposed that the value of expected growth in rate base assets may encourage a premium. However, Dr. Booth submitted that financial theory indicates that growth is of value only if the expected ROE exceeds the fair rate of return. The Commission agrees with this. If there were ample opportunities to invest at the same or higher returns elsewhere, then the opportunity to grow rate base has no value.

117. Mr. Engen offered that a premium may signal an expectation of higher regulated return levels in the future. Dr. Booth submitted that, if this were the case, it would suggest that the current return was too low and accordingly the current price-to-book ratio should be below one. The Commission agrees.

118. Mr. Engen argued that a premium may be paid if investors expected that operating efficiencies would lead to higher earnings. Dr. Booth submitted that, under regulation, cost savings are meant to be passed on to customers. However, the Commission recognizes that, under the current rate base rate of return regime, operating savings can result in earnings beyond the regulated return and investors are entitled to retain these earnings during a test year. This provides incentives for increased efficiencies, but these efficiencies are later realized by customers in the next test period. The Commission is also aware that many of the utilities it regulates frequently achieve operating efficiencies and earn returns beyond the allowed return.

119. Likewise, Mr. Engen suggested that performance-based regulation (PBR) opportunities may have incented investors to pay a premium. Dr. Booth submitted that this was partly correct, but that a price-to-book ratio of 1.8 would require very large, if not impossible, efficiencies. The Commission agrees that the opportunity to adopt performance based regulation may be a justification for a premium, given that the opportunity to retain earnings above the regulated return is enhanced under PBR.

120. Finally, Mr. Engen argued that access to attractive unregulated assets and collateral benefits or synergies, or access to new territory, or a desire to protect one's existing regulated franchise may be reasons to pay a premium. The Commission agrees that these may arguably be business reasons for the payment of a premium.

121. In the Commission's view, it would not be rational for investors to purchase a utility at a premium, unless it was of the view that it could earn at least a market rate of return on the investment despite paying the premium. The payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational. A possible conclusion is that such purchases, at substantial premiums, would indicate that the awarded returns were more than sufficiently attractive.

122. Again, the Commission finds, as it did in Decision 2009-216, that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies. With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood. In these circumstances, it is difficult for the Commission to draw any

conclusions about the significance of this transaction to the establishment of a fair return on equity. Nonetheless, the Commission agrees with the observation that a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. Estimates of the price to book ratio for the 2011 AltaLink transaction generally exceed 1.0 by a significant margin. This appears to be evidence that the allowed ROE at the time of the purchase was at least adequate.

3.8 Returns available on high grade corporate bonds

123. CAPP referenced the fact that in Decision 2009-216, the Commission concluded that the high corporate bond spreads at that time justified the addition of 50 basis points to the results derived from methodologies like CAPM that rely solely on historical data to estimate the equity premium above the risk free rate.[91]

124. Dr. Booth indicated that studies by the Bank of Canada have shown that 63 per cent of the increase in corporate spreads during the credit crisis was due to liquidity problems in the bond market and only 37 per cent was due to default risk. He argued it is only the default risk that affects equity investors.[92] Dr. Booth indicated that, in contrast to corporate bond liquidity, equity market liquidity had increased during the credit crisis and equity investors should not be rewarded for a liquidity problem in the bond markets that does not affect equity holders.[93]

125. Dr. Booth saw a justification for no more than 25 basis points at this time, in respect of higher than historical corporate bond spreads, but used a range of 25 to 50 basis points for this allowance.

126. The Utilities submitted that spreads on Canadian A-rated utility bonds, as at July 29, 2011, were at 141 basis points, which is well above the 95 basis point average for 2003 through 2007.[94]

127. In Decision 2009-216, the Commission stated:

> As has occurred throughout this Proceeding, the Commission must weigh conflicting expert testimony on various factors impacting the determination of a fair return for Alberta utilities. The Commission considers the increased high grade Canadian corporate bond spreads which occurred during the financial crisis and which continued to occur, albeit on a downward trend, at the close of the Proceeding demonstrate that there has indeed been some re-pricing of risk on debt securities. Equity investors in high grade rated companies have more default risk than do debt investors. An increase in debt investor return expectations ordinarily must be considered to result in an increase in return expectations for equity investors otherwise equity investors would not accept the incremental risk associated with equity ownership. The Commission finds that there is insufficient evidence on the record of the proceeding that illiquidity in the Canadian bond market during the financial crisis can account for a significant portion of the increased risk premium demanded by bond investors.
>
> It remains an open question whether corporate bond spreads will quickly, if ever, return to pre-financial crisis levels. In particular, it remains uncertain that the re-pricing of risk

91 Exhibit 207, CAPP argument, paragraph 61 referencing Decision 2009-216 at paragraph 311.
92 Exhibit 207, CAPP argument, paragraph 64.
93 Exhibit 207, CAPP argument, paragraph 70.
94 Exhibit 209, Utilities argument, paragraph 23.

> observed in high grade Canadian corporate bond spreads in the period up to the close of the Proceeding will end in either 2009 or 2010. In these circumstances, it is reasonable to conclude that the actual return expectations of utility equity investors in 2009 and 2010 would be at least 50 basis points higher than estimates of equity return expectations derived from methodologies like CAPM which rely solely upon historical data and the risk free rate.

128. As discussed in Section 3.2 above, the Commission considers that spreads have decreased from the 2009 levels but have not returned to their historic levels. The Commission also notes that it has set the top end of its CAPM market equity risk premium, assuming, on the basis of Ms. McShane's evidence, that the market equity risk premium may be higher than its historic average at this time of historically low interest rates. For these reasons, the Commission is not convinced that any addition to CAPM results is needed to account for the reduction in corporate bond spreads at this time.

3.9 Pension, investment manager and economist return expectations

129. In regards to the return expectations of pension and investment managers and others, the UCA submitted that, in December 2010, CIBC World Markets had forecast total returns on the Canadian market of 8.0 to 9.0 per cent over the next decade. In addition, the UCA submitted that BMO Capital Markets had recently forecast an equity market return of 6.5 to 7.2 per cent, with a market equity risk premium of 3.5 to 4.2 per cent and, that the mid-point of estimates from Fiduciary Trust Company of Canada for the equity market return and market equity risk premium (relative to yields on 10-year Government of Canada bonds) were eight per cent and five per cent, respectively. The UCA also submitted that, in Mercer's 2011 Fearless Forecast survey of Canadian and global institutional investment managers, the median expected return for the TSX Composite is 8.5 per cent. The 2011 Towers Watson survey results, which show participants' expectations for the TSX Composite Index return in the short, medium and long-term, indicated that the median or 50th percentile short-term expectation for 2011 was eight per cent, with the median medium and long-term expectations below eight per cent.[95]

130. Drs. Kryzanowski and Roberts and Dr. Booth also referred to, and summarized, the results of surveys conducted by Drs. Fernandez and del Campo of forward-looking estimates of the market equity risk premium and total equity market returns by academics, financial professionals, and corporate finance executives. The UCA submitted that, as these surveys show, the mean and median forward-looking market equity risk premium estimates are in the low five per cent range, with academics generally providing the highest estimates. The estimates declined from 2009 to 2010.[96] The Commission notes that using a risk-free rate of 3.4 to 3.8 per cent, this would imply market returns in the range of eight to nine per cent.

131. Drs. Kryzanowski and Roberts also described surveys of U.S. chief financial officers conducted by Drs. Graham and Harvey concerning expected returns on the S&P 500. They summarized the results of a series of such surveys in their Schedule 2.9.3.2a, which shows an average expected overall market return of less than 7 per cent for the most recent periods and expected market equity risk premiums for those periods of 3 per cent or less.[97]

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95 Exhibit 210, UCA argument, paragraph 122.

96 Exhibit 210, UCA argument, paragraph 123.

97 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.9.3.2a.

132. The Utilities submitted that survey results do not provide a reliable basis for estimating the cost of capital because they do not provide supporting quantitative analysis and do not indicate whether the results are in the nature of a geometric or arithmetic average. The Utilities also stated that corporations making investment decisions were using hurdle rates of 14 per cent at a time when the 10-year Treasury yield was four per cent.[98]

133. The Commission finds that the evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

3.10 Impact of growth on required ROE

134. The UCA submitted that, in principle, it was not persuaded that the potential for growth should be a factor in determining an appropriate ROE. If the allowed ROE is set equal to the risk-adjusted cost of capital for utility investments, investors should be indifferent as between utility investments and the alternatives available in the market. If it is established that the potential for growth is a highly attractive attribute for utility stocks, this suggests that the allowed ROEs are generous. The more enthusiastic utilities and utility investors are about potential growth, the stronger the implication that allowed returns exceed the true cost of equity.[99]

135. The Utilities submitted that growth is attractive and that it could result in a reduction of existing price-to-book ratios over time, but that growth does not suggest a lower ROE should be approved. The Utilities submitted that extremely large growth can result in increased financial risk.[100]

136. The Commission acknowledges that investors should, in theory, be indifferent to growth if growth is only expected to provide a risk-adjusted return readily available elsewhere in the market. The Commission notes that growth in utilities requires additional earnings to be retained rather than paid out as dividends or may require the injection of equity for which the investor will only receive the allowed ROE. In general, the intervener experts appeared to view their ROE recommendations as being somewhat generous. Ms. McShane submitted the ROE should be above the bare bones cost.

137. In addition, the Commission notes the evidence of Mr. Engen who submitted that growth in earnings per share (EPS) is what is important to investors[101] and that EPS accretion is widely used and accepted by the investment community as an important rationale in justifying acquisitions. He submitted that whether, and under what circumstances, financial theory would or would not support the view that EPS accretion increases value is not relevant to whether the EPS accretion is used in practice to support acquisitions.[102]

138. In the Commission's view, it is reasonable to conclude that investors value growth only if the expected growth provides the necessary return. Investors might accept a somewhat lower expected and awarded ROE for a high-growth utility, as compared to a low-growth utility, but only if they expect that the utility will be able to earn in excess of its awarded ROE.

98 Exhibit 220, Utilities reply argument, paragraph 69.
99 Exhibit 210, UCA argument, paragraph 128.
100 Exhibit 209, Utility argument, paragraphs 118-121.
101 Exhibit 86.01, evidence of Aaron M. Engen, page 10, lines 18 and 19.
102 Exhibit 152.01, rebuttal evidence of Aaron M. Engen, paragraph A24.

3.11 The Commission's awarded ROE

139. The Utilities requested an ROE of 10.375 per cent based on the expert evidence of Ms. McShane.

140. Dr. Booth's position was that no Alberta utility had difficulty raising capital since the last generic cost of capital proceeding and that no increase in ROE is warranted. If anything, the ROE should be reduced.

141. The UCA submitted that the fair ROE is in the range of 8.0 to 8.5 per cent and the Commission should approve an ROE not higher than 8.3 per cent.[103]

142. The CCA accepted the ROE recommendation of Drs. Kryzanowski and Roberts of 8.3 per cent for 2011and recommended that the Commission approve an ROE of 8.4 for 2012.[104]

143. In this decision, the Commission has set out to establish a fair rate of return on equity for 2011 and going forward for the utility companies it regulates. The awarded ROE must be based on an estimate of the risk-adjusted opportunity cost of equity capital. The Commission must estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than in other investments of similar risk that are available in the market. The difficulty that the Commission faces is that the ROEs that are available to be earned on investments of similar risk are not directly observable.

144. In keeping with the Commission's determinations above, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities. The Commission has reviewed the models and approaches adopted by the various parties and, based on the analyses above, has found that some of the CAPM and DCF results filed in this proceeding (including an analysis of the expected overall Canadian stock market returns) will form the primary basis for its ROE determination.

145. In making its ROE determination, the Commission is mindful of the uncertainties created by the financial crisis that began in the third quarter of 2007 and its lingering effects, which have not fully abated. The Commission found that, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

146. The Commission found that a reasonable CAPM estimate is in the range of 6.4 to 9.0 per cent based on its analysis of the forecast risk free rate, the market equity risk premium and beta.

147. The Commission also found that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming the equity ratio has been set to target a credit rating in the A range. The Commission concludes that the DCF results appear to suggest that investors expect a return of about nine per cent on utility investments, assuming investors agree with analysts' growth forecasts. However, as noted above, the Commission remains concerned about the impact of optimistic growth forecasts in this result. This concern is bolstered by the results of the DCF analysis applied to the overall market which suggested returns in the range of 7.1 to 10.1 per cent.

[103] Exhibit 210, UCA argument, paragraph 138 and 149.
[104] Exhibit 211, CCA argument, paragraphs 32 and 77.

148. The evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

149. Having considered and weighed all of the evidence and assessed it in the context of the lingering credit market volatility, and recognizing that there has been a reduction in the risk free rate of some 60 basis since 2009 by the close of the record of this proceeding, the Commission finds that some reduction in the ROE awarded in Decision 2009-216 is warranted. Accepting that some of the reduction in the risk free rate may be offset by an increase in the market equity risk premium, the Commission considers that a generic ROE of 8.75 per cent is reasonable for 2011.

4 Return to the formula adjustment in 2012

150. Having determined the generic rate of return on equity for 2011, the Commission must consider how that rate of return will be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula approach discontinued in 2009 should be reinstated and if so, what type of formula for annual adjustments to ROE should be adopted by the Commission.

151. In Decision 2004-052, the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or Board) adopted the annual adjustment formula for setting the generic ROE based on 75 per cent of the change in long Canada bond yields:[105]

$$ROE_{New} = \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield})$$

152. This formula was discontinued in Decision 2009-216, because of the economic crisis conditions observed at the time of the 2009 GCOC proceeding. Specifically, the Commission concluded that the historical relationships upon which the formula was based had not yet been re-established in the aftermath of the financial crisis.[106]

153. In this proceeding, the Utilities recommended that the Commission not adopt an automatic adjustment formula at this time for two reasons. First, the Commission's performance-based regulation (PBR) initiative for distribution utilities could change the risk profile of the distribution utilities and may require the re-evaluation of the fair ROE. Second, as outlined in Section 3.2 above, the Utilities argued that there remained considerable risk in the global economy and capital markets.[107]

154. However, the Utilities submitted that, if the Commission determined that an automatic adjustment mechanism is warranted for 2012, the formula adopted by the OEB in its Report EB-2009-0084 should be used. The OEB formula is as follows:

$$\begin{aligned} ROE_{New} = {} & \text{Initial ROE} + 50\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ & + 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

155. The Utilities indicated that Ms. McShane's independent analysis supported the factors and weightings used in this formula, based on the historical relationships among the utility cost of equity, long-term government bond yields and corporate bond yield spreads.

105 Decision 2004-052, page 32.
106 Decision 2009-216, paragraphs 418-420.
107 Exhibit 209, Utilities argument, paragraphs 122.

156. The UCA witnesses, Drs. Kryzanowski and Roberts, agreed that the formula adopted by the OEB reflects an appropriate adjustment structure. The UCA's position was that the Commission should return to a formula approach to setting allowed ROEs on a generic basis for the Alberta utilities because of the practical advantages resulting from regulatory efficiency. The UCA submitted that a properly designed ROE formula provides reasonably accurate estimates of the true cost of equity over a reasonable period.

157. Based on their opinion that credit markets had normalized, Drs. Kryzanowski and Roberts did not share the Utilities' view that the return to a formula would not be beneficial at this time. Furthermore, the UCA witnesses pointed out that introducing a utility bond spread component will mitigate any remaining concerns as to the financial market volatility.[108] With respect to the Utilities' concerns related to the ongoing PBR proceeding, the UCA expressed the opinion that the PBR may not involve any material changes in business risk. Additionally, the UCA indicated that one would expect changes in business risk to be addressed through capital structure adjustments rather than ROE adjustments, in accordance with past practice in Alberta.[109]

158. Dr. Booth, testifying on behalf of CAPP, proposed a modified formula that reflects 75 per cent of the change in the Government of Canada long bond yield and 50 per cent of the change in utility bond spreads:

$$\begin{aligned} ROE_{New} = {} & \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ & + 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

159. Dr. Booth explained that the 75 per cent adjustment factor is consistent with the formula that the Commission and its predecessor used between 2004 and 2009, and is supported by his analysis of market and utility risk premia.[110] By contrast, CAPP submitted that the formula proposed by Ms. McShane, with the 50 per cent adjustment factor for the Government of Canada long bond yield, would imply ROEs higher than those determined by regulators in that time period, including this Commission's predecessor.

160. CAPP also pointed out that the Quebec Régie de l'Energie accepted Dr. Booth's modified formula in a recent Gazifere decision (D2010-147) and will use it beginning in 2012.

161. The CCA indicated that none of the formulae proposed in this proceeding appear to be based on any financial analysis as to their validity and submitted that it prefers the Commission not return to an adjustment formula but periodically set a generic ROE.[111]

Commission findings

162. In Decision 2009-216, the Commission observed that due to the then-existing credit crisis conditions, the relationships among various market indicators were not stable and decided not to employ an adjustment formula for 2010. As discussed in Section 3.2 above, the evidence in this proceeding demonstrated that, although there has been some improvement in the financial environment, credit markets remain volatile. Referring to the financial community's concerns with the European sovereign debt, Dr. Booth summarized this view as follows:

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108 Exhibit 210.02, UCA argument, paragraph 16.
109 Ibid., paragraph 21-22.
110 Exhibit 78.02, evidence of Laurence D. Booth, paragraphs 180-184.
111 Exhibit 211, CCA argument, paragraph 21.

> The fact is that we don't know all of the linkages in the credit default swap market, so that is a palpable nervousness in the bond market. That is something that is highly unusual. It is still there. It is nowhere near as bad as it was three years ago, but it is there, and we do not have a normal market.[112]

163. As the Commission explained in Decision 2009-216, the 2004 formula was developed based on the expectation that the required rate of return for utilities moves in the same direction as the return on 30-year Government of Canada bonds. The Commission found that, during a time of adverse market conditions, this expected relationship between interest rates and the required return on equities does not necessarily hold.[113]

164. All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula. Moreover, as Dr. Booth's explained, such a formula would be counter-cyclical because allowed returns would increase in difficult economic times and decrease in strong economic times, but over the business cycle this will average out.[114]

165. The Commission agrees with the interveners' arguments that a modified formula that accounts for changes in corporate bond spreads partially corrects for the drawbacks of a single-variable formula. Nevertheless, the Commission has considered the evidence of continuing credit market volatility and finds that a return to the formula mechanism for annual adjustments to ROE is not warranted at this time.

166. Accordingly, the Commission will not employ an adjustment formula for 2012. At the same time, as noted in the Decision 2009-216, the Commission is not prepared to preclude a return to some form of formula-based adjustment mechanism in the future, once the capital markets have stabilized and are once again considered reasonably predictable.[115] As such, the Commission is prepared to revisit the re-introduction of an automatic adjustment mechanism once the credit markets are more predictable and the Commission can be confident that the relationships implied in the formula will continue.

167. As explained in Section 3.11 of this decision, the Commission has determined that a fair generic rate of return on equity for Alberta utilities for 2011 is 8.75 per cent. Given the December 8, 2011 issue date of this decision and the fact that the record closed on September 9, 2011, the Commission is mindful of the proximity of this decision date to 2012. Considering the substantial drop in interest rates by the close of the record, the Commission sees no reason to find that the risk free rate of 3.4 to 3.8 per cent that it has accepted as reasonable for 2011 would not also be reasonable for 2012. The Commission does not consider that adjustments to any of its other findings with respect to the establishment of a reasonable ROE for 2011 are warranted for 2012. Accordingly, the Commission concludes that an ROE of 8.75 per cent is fair for both 2011 and 2012.

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[112] Transcript, Volume 7, page 911, lines 8 to 13.
[113] Decision 2009-216, paragraphs 417 and 418.
[114] Exhibit 207.02, paragraph 97.
[115] Decision 2009-216, paragraphs 420-422.

168. In addition, the Commission is setting the allowed ROE for 2013 at 8.75 per cent on an interim basis. The Commission will initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis. The Commission considers that establishing an allowed ROE for 2012 and setting an interim ROE for 2013 will provide for a more supportive, and predictable regulatory environment.

5 Capital structure matters

5.1 Introduction

169. To satisfy the fair return standard, the Commission is required to determine a capital structure (equity ratio) for each of the utilities that are the subject of this proceeding. In this decision, the Commission has established a generic ROE of 8.75 per cent which will be applied uniformly to all of the utilities. Consistent with the approach taken in the previous GCOC decisions, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

170. As the Commission noted in Decision 2009-216, in general, the return required by investors on debt is lower than the return required on equity. This is because debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in the capital increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk: debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and pay them their expected return.

171. This risk is usually assessed by various interest coverage calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor's (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various interest coverage metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations.

172. In this decision, the Commission will establish the capital structure for each utility that, in the Commission's judgment, would allow a stand-alone utility to maintain a credit rating in the A range, subject to company-specific circumstances. To do so, the Commission will first consider the impact of changes in the credit environment since the time of the 2009 GCOC proceeding. The Commission will then analyze the equity ratios that are required to attain the minimum credit metrics that were identified in Decision 2009-216. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted.

173. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2009-216 with the equity ratios recommended by the applicants and interveners in this proceeding.

Table 7. Recommended vs. currently approved equity ratios

	Last approved[116] (%)	Recommended by the Utilities[117] (%)	Recommended by the UCA[118] (%)	Recommended by the CCA[119] (%)	Recommended by CAPP[120] (%)
Electric and Gas Transmission					
ATCO Electric TFO	36	38	34	36	
AltaLink	36	38	36	36	
ENMAX TFO	37	39	30	36	
EPCOR TFO	37	39	33	36	
ATCO Pipelines	45	47 (for 2011) 44 (for 2012)[121]	42 (for 2011) 30 (for 2012)	42 (for 2011) 40 (for 2012)	35 (for 2012)
Electric and Gas Distribution					
ATCO Electric DISCO	39	41	35	37	
ENMAX DISCO	41	43	35	39	
EPCOR DISCO	41	43	35	39	
ATCO Gas	39	41	34	37	
FortisAlberta	41	43	35	39	
AltaGas	43	45	40	41	

5.2 Credit environment

174. Much of the ROE and capital structure discussion in this proceeding centered on whether markets have returned to normal and whether the credit crisis discussed in Decision 2009-216 has passed. As discussed in more detail in Section 3.2 above, the Utilities cautioned that, while markets improved since the peak of the crisis, they have not returned to normal conditions. The interveners argued that economic parameters relevant to the cost of capital determinations have improved significantly and could be considered normal.

175. The Utilities submitted that, due to the persistence of significant downside risks to Canadian and global capital markets and economies, the two per cent across-the-board increase in common equity ratios approved in Decision 2009-216 was still relevant. Furthermore, Ms. McShane, who appeared on behalf of the Utilities, expressed her opinion that rating agencies do not view this across-the-board increase as temporary and, therefore, any reduction to equity ratios in the current proceeding could send negative signals to the market. As such, Ms. McShane used the capital structures approved in Decision 2009-216 as the point of departure in developing the Utilities' generic capital structure recommendations.[122]

176. In contrast, the UCA witnesses, Drs. Kryzanowski and Roberts, recommended that the Commission reverse the two percentage point equity ratio increase it awarded to all of the utilities in the 2009 GCOC. Their reasoning was that the additional two per cent was primarily awarded in order to account for the effects of the credit crisis, and because the credit crisis is

116 Decision 2009-216, Table 17, page 107.
117 Exhibit 209, Utilities argument, paragraph 129 (unless noted otherwise).
118 Exhibit 210.02, UCA argument, paragraph 215.
119 Exhibit 211, CCA argument, paragraph 58 (corrected as per Exhibit 213).
120 Exhibit 207.02, CAPP argument, paragraph 97.
121 Exhibit 208, ATCO Pipelines argument, paragraph 1.
122 Exhibit 209, Utilities argument, paragraphs 137-138.

over, there is no need to continue providing the Utilities with that additional financial flexibility.[123]

177. The UCA witnesses did not agree with Ms. McShane's position that the two per cent increase awarded in Decision 2009-216 was permanent and submitted that such an approach advocates the need for a permanent increase in shareholder returns, not because of what the actual capital market conditions were at the time of the decision, but because of the risk that problems similar to the financial crisis might arise in the future. Drs. Kryzanowski and Roberts submitted that the credit crisis was a rare event occurring approximately once in 75 years, and as such, it would not be fair to provide a permanent bonus to utility shareholders in order to insulate them against the potential effects of a near-catastrophic event that may not happen again for decades.[124]

178. The CCA supported the removal of the across-the-board two per cent increase in equity ratios awarded in the 2009 GCOC decision as proposed by the UCA, with the exception of the TFOs and ATCO Pipelines as further discussed below.[125] CAPP did not recommend any equity ratios other than for ATCO Pipelines, but did note that the financial market situation had stabilized and the need for any adjustment on this account was significantly reduced from the time of the 2009 GCOC decision when the Commission remained concerned about an uncertain future.[126]

Commission findings

179. As the Commission observed in Section 3.2 above, by the time of the 2011 GCOC hearing, economic parameters relevant to cost of capital determinations had improved significantly since the 2009 GCOC proceeding. Therefore, while cognizant of the lingering uncertainty in the debt markets related to concerns over sovereign debt in Europe and the U.S., the Commission agrees with Dr. Booth's opinion that the need for an adjustment to account for the financial crisis is reduced from the time of the 2009 GCOC decision.

180. However, as the Utilities pointed out, the credit crisis was only one of several factors that led to the two percentage point increase in equity thickness awarded in Decision 2009-216. Therefore, the Commission does not accept the UCA's proposal to reverse the two per cent equity ratio increase, solely because the credit crisis concerns have somewhat abated.

5.3 Credit metric considerations

5.3.1 Financial ratios, capital structure and actual credit ratings

181. Credit ratings measure the credit-worthiness of a firm. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments. This, in turn, allows the company to borrow at a lower interest rate. Utilities usually seek to maintain a credit rating in the A range.

182. As discussed in Section 5.1Error! Reference source not found. above, credit metrics (financial ratios) are an important part of bond rating agencies' considerations when assessing

123 Exhibit 210.02, UCA argument, paragraph 225.
124 Ibid., paragraphs 228-321.
125 Exhibit 211, CCA argument, paragraph 52.
126 Exhibit 207.02, CAPP argument, paragraph 90.

the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:

- EBIT coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs
- funds for operation (FFO)/debt, which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt
- FFO coverage, which is the company's funds from operations plus interest divided by total interest costs

183. The Commission observed in Decision 2009-216 that a number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby making it possible to directly see the equity ratios and credit metrics that are associated with stand-alone regulated utilities that have credit ratings in the A range. Consequently, the Commission examined the credit ratings of those companies for which credit rating reports were available on the record, in order to gain some insight into the credit metrics required to achieve an investment grade credit rating for a stand-alone utility.

184. In Decision 2009-216, the Commission observed the following minimum credit metrics associated with an A-range credit rating:[127]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3%

185. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

186. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid point of 38.5 per cent.[128]

187. The sample group of utilities that were examined in arriving at this observed range of equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

188. In this proceeding, the Utilities noted that the importance of debt ratings in the A category for the Alberta utilities was reviewed in detail in the 2009 GCOC process, when the Commission established a capital structure that would allow a stand-alone utility to maintain a credit rating in the A range. In that regard, the Utilities submitted that there have been no fundamental changes in the capital markets or utility requirements for access to debt capital that would warrant revisiting that conclusion.[129]

[127] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[128] Ibid., paragraph 359.
[129] Exhibit 209, Utilities argument, paragraphs 135.

189. The Utilities' position on the acceptability of the minimum credit metrics set out in Decision 2009-216 was not explicitly stated in argument, but appeared to be implicitly accepted. In particular, Ms. McShane testified that she used the minimum credit metrics observed in Decision 2009-216 as a point of departure.[130]

190. In her evidence, Ms. McShane also provided a review of changes in the equity ratios adopted for the Canadian peers of the Alberta utilities. Specifically, Ms. McShane indicated that, since the close of the oral portion of the last GCOC proceeding, there have been a number of increases in equity ratios approved by regulators. Based on her observation that the average regulated common equity ratio for utilities outside Alberta was 40 per cent, Ms. McShane considered this number to be a reasonable benchmark equity ratio for an average risk Alberta utility.[131]

191. The UCA submitted that it accepted the minimum credit metrics set out in Decision 2009-216 as reasonable guidelines, but emphasized Drs. Kryzanowski and Roberts' view that credit ratings do not follow a formula and depend on numerous qualitative factors and an examination by the rating agencies of numerous aspects of the businesses for which the ratings are prepared. The UCA witnesses also noted that their recommended equity ratios were generally consistent with the minimum equity ratios identified by the Commission.[132]

192. The CCA submitted that it did not accept benchmarking to the awards of other regulators as a tool for determining capital structure, as this method leads to a circularity problem. The CCA noted it accepts regulatory benchmarking only for information purposes, and only for comparison of methods, not for the actual awards.[133]

Commission findings

193. As discussed in Decision 2009-216, utilities usually seek to maintain their credit rating in the A range to avoid paying higher interest rates on debt typically associated with lower rating categories. Furthermore, as the Commission observed recently in Decision 2011-453[134] dealing with AltaLink's 2011-2012 GTA, a lower credit rating may limit a company's access to capital markets. In particular, the Commission noted that, as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions.[135]

194. Therefore, the Commission reaffirms its finding that it is important to target the debt ratings for the Alberta utilities in the A category, as established in the 2009 GCOC process. The Commission agrees with the parties to this proceeding that minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, can be accepted as reasonable guidelines for the purposes of this proceeding.

195. With respect to Ms. McShane's recommended benchmark equity ratio of 40 per cent, the Commission agrees with the CCA that equity ratios awarded by other regulators are of interest

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130 Transcript, Volume 2, page 242, lines 8 to 11.
131 Exhibit 86.01, Kathleen McShane Opinion, pages 30-32.
132 Exhibit 210.02, UCA argument, paragraphs 156-160.
133 Exhibit 211, CCA argument, paragraphs 50 and 51.
134 Decision 2011-453: AltaLink Management Ltd. 2011-2013 General Tariff Application, Application No. 1606895, Proceeding ID No. 1021, November 18, 2011.
135 Decision 2011-453, paragraph 798.

but are far from determinative of the capital structure this Commission should award. Furthermore, in Decision 2009-216, the Commission observed the actual equity ratios of the utilities in the A range rating category. Ms. McShane did not specify whether her analysis of capital ratios awarded by other regulators was limited only to the A-rated utilities.

5.3.2 Equity ratios associated with minimum credit metrics

196. In Decision 2009-216, the Commission provided a sensitivity analysis of the three key credit metrics to changes in the equity ratio. Assuming an embedded cost of debt of 6.5 per cent, an ROE of 8.75 per cent (the 2009 placeholder level), an income tax rate of 29 per cent, and assuming the annual depreciation expense as a percentage of invested capital equal to the utility average of six per cent, the Commission calculated the following minimum equity ratios required to achieve the observed minimum credit metrics:[136]

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 34 per cent.
- Minimum equity ratios in the range of 30 to 36 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 33 per cent was required to achieve an FFO coverage ratio of at least 3.0.

197. Ms. McShane proposed to update the Commission's analysis in Decision 2009-216 by making three adjustments. The first was to assume a reduction in average debt costs for the average utility. The second was to include an assumed five per cent construction work in progress (CWIP) in the credit metric calculation for the hypothetical average utility. The third involved recalculating the hypothetical credit metrics using the lower tax rates that apply in 2012.

198. With respect to the first adjustment, Ms. McShane noted that a review of the 2009 embedded debt costs provided by the Alberta utilities in their Rule 005[137] filing requirements indicated that there has been a marginal decline since 2007 (less than 10 basis points). Therefore, Ms. McShane proposed to use a 6.4 per cent average embedded cost of debt as compared to the 6.5 per cent rate used by the Commission in Decision 2009-216, which would have the effect of improving credit metrics and decreasing the necessary equity ratio.[138]

199. Next, Ms. McShane indicated that even a relatively small percentage of CWIP has a measurable impact on EBIT interest coverage ratios. Based on her observation that the median of CWIP as a per cent of total regulated assets in 2009 for the Alberta utilities was around five per cent, Ms. McShane proposed to include this amount of CWIP in the calculations of equity ratios required to achieve the minimum EBIT coverage ratios observed by the Commission.

200. With respect to the impact of income taxes, Ms. McShane indicated that, in 2012, the combined provincial and federal corporate income tax rate will be 25 per cent, compared to the 29 per cent used in the analysis set out in Decision 2009-216. Furthermore, the Utilities' witness indicated that the median actual effective income tax rate for the taxable Alberta Utilities in 2009 (excluding AltaLink) was less than half the statutory combined rate.[139] As such, Ms. McShane

136 Decision 2009-216, paragraphs 352, 354 and 356.
137 AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
138 Exhibit 86.01, Kathleen McShane Opinion, page 25, lines 638-646.
139 Ibid., page 27, lines 674-683.

proposed to use the 12.5 per cent tax rate in equity ratio calculations, which represents 50 per cent of the 2012 statutory tax combined rate of 25 per cent.

201. Incorporating these recommended assumptions regarding the embedded cost of debt, effective tax rate and presence of CWIP,[140] the Utilities provided updated versions of the Commission's analysis of equity ratios in Decision 2009-216 as follows:

Table 8. Credit metrics compared to equity ratios – McShane's evidence

	EBIT coverage		FFO/Debt		FFO coverage	
Equity Ratio	Table 13 in Decision 2009-216	Updated and expanded assumptions	Table 14 in Decision 2009-216	Updated and expanded assumptions	Table 15 in Decision 2009-216	Updated and expanded assumptions
30%	1.8	1.6	12.32	11.71	2.90	2.78
31%	1.9	1.6	12.63	12.00	2.94	2.82
32%	1.9	1.6	12.94	12.29	2.99	2.87
33%	1.9	1.7	13.26	12.60	**3.04**	2.92
34%	2.0	1.7	13.60	12.92	3.09	2.97
35%	**2.0**	1.7	13.94	13.25	3.14	**3.02**
36%	2.1	1.8	**14.30**	13.58	3.20	3.07
37%	2.1	1.8	14.66	13.93	3.26	3.13
38%	2.2	1.9	15.04	**14.29**	3.31	3.18
39%	2.2	1.9	15.43	14.66	3.37	3.24
40%	2.3	1.9	15.83	15.04	3.44	3.30
41%	2.3	**2.0**	16.25	15.44	3.50	3.36
42%	2.4	2.0	16.68	15.85	3.57	3.43
43%	2.4	2.1	17.13	16.27	3.63	3.49
44%	2.5	2.1	17.59	16.71	3.71	3.56
45%	2.6	2.2	18.07	17.16	3.78	3.63
46%	2.6	2.2				
47%	2.7	2.3				

Source: Exhibit 209, Utilities argument, Attachment 2.

202. Based on her evaluation of the net effect of the three adjustments on credit metrics (as presented in Table 8 above), Ms. McShane concluded that an increase in the common equity ratios of no less than two percentage points was warranted. The highlighted examples in the table illustrate that a minimum two percentage point equity ratio increase is necessary to restore the credit metrics to the levels that applied under the 2009 calculations, given Ms. McShane's assumptions.

203. The UCA took issue with the Utilities' inclusion of CWIP and a lower tax rate in the credit metrics calculation. The UCA submitted that, in Decision 2009-216, the Commission implicitly took these factors into account and the resulting equity ratios were well received by the rating agencies. In the UCA's opinion, the relevant facts or circumstances have not changed

[140] Utilities' assumptions: embedded cost of debt of 6.4 per cent, ROE of 8.75 per cent, effective tax rate of 12.5 per cent (50 per cent of 2012 statutory tax rate), 5.0 per cent CWIP as percentage of regulated assets, depreciation rate of 6.0 per cent.

since 2009, and as such, Ms. McShane's analysis was simply an arbitrary re-definition of the Commission's model.[141]

204. The UCA also noted that, in the case of the two transmission utilities that have the highest levels of CWIP – ATCO Electric and AltaLink, the Commission addressed this issue in other ways in their respective GTAs.[142]

205. With respect to Ms. McShane's adjustment related to lower tax rates, the UCA observed that any changes in tax rates affects only the EBIT coverage credit metric, since the FFO/debt and FFO interest coverage metrics are after tax measures. The UCA also submitted that, under a flow-through tax regime, changes in either statutory or effective tax rates do not have any material impact on bondholders or the creditworthiness of the utilities, because the funds collected for taxes on a forecast basis are earmarked for payment to the tax authorities and so are not available to pay creditors.[143]

206. The UCA conceded that lower tax rates reduce the EBIT interest coverage ratio but argued that credit rating agencies do not take the "rigidly rule-based formulaic approach" to understanding credit ratings and credit metrics, and arrive at a balanced assessment of creditworthiness that takes into account all of the moving parts that affect the interests of bond investors.[144] As a result of these considerations, the UCA argued there was no need to update the Commission's credit metric analysis tables in Decision 2009-216.

207. The CCA agreed with the UCA's analysis on CWIP and effective income taxes. Specifically, the CCA argued that there should be no adjustment for income tax rates because deferred income tax must ultimately be paid and financial analysts have not identified deferred income taxes as a risk. In addition, the CCA observed that the effective income tax rate varies greatly from utility to utility and, therefore, any required adjustments should be made on a utility-specific, rather than generic, basis.[145]

208. Similarly, the CCA objected to the across-the-board adjustment for CWIP. The CCA expressed its opinion that a large amount of CWIP is currently a problem for the TFOs but not for all the utilities. The CCA submitted that there is little risk from CWIP and that no adjustment to ROE was necessary for any amount of CWIP.[146]

209. In reply argument, the Utilities submitted that the absence of downgrades does not constitute an appropriate basis for evaluating the reasonableness of Ms. McShane's recommendations and argued that it was necessary to include CWIP amounts in the equity ratio analysis so that the credit metrics identified by the Commission as minimums would be achievable.

210. The Utilities also took issue with the UCA's argument that the income tax allowance is earmarked for payment to the income tax authorities and is not available for payment to creditors. The Utilities submitted that this view does not comport to the manner in which the debt rating agencies evaluate a company's ability to meet its debt obligations. The Utilities explained

141 Exhibit 210.02, UCA Argument, paragraphs 167 and 173.
142 Ibid., paragraph 170.
143 Ibid., paragraphs 178-179.
144 Ibid., paragraphs 182-184.
145 Exhibit 211, CCA argument, paragraphs 37-38.
146 Ibid., paragraph 40.

that, since interest expense is tax-deductible, income taxes payable are partly a function of how much interest is paid and therefore, it is logical that the debt rating agencies would consider the pre-tax funds that a company has available to cover its debt obligations.[147]

Commission findings

211. In Decision 2009-216, the Commission presented its analysis of equity ratios required to achieve the minimum credit metrics considered to be associated with credit ratings in the A range. The Commission expressly stated that this analysis did not include the consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.[148]

212. In this proceeding, the Utilities pointed out that even a small percentage of CWIP has a measurable impact on credit metrics. As noted in Decision 2009-216, the Commission agrees that the presence of CWIP lowers the credit metrics.[149] In fact, recognizing this reality, the Commission, through its issues list, invited parties to update the credit metric tables with relevant assumptions as to the typical level of CWIP for the Alberta utilities.

213. As discussed further in this section, the Commission agrees with the UCA and the CCA that the adjustment for CWIP is not necessary for ATCO Electric TFO and AltaLink, given that this matter was recently addressed in their respective GTAs. However, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for other Alberta utilities.

214. Specifically, the UCA argued that updating the Commission's tables with typical amounts of CWIP and lower income taxes advocates a formulaic approach to credit metrics. The Commission accepts the UCA's point that rating agencies supplement their analysis of credit metrics with a number of other considerations to arrive at a balanced assessment of a company's creditworthiness. As discussed in Section 5.6 below, the Commission's determination on the matter of capital structure is not limited to credit metric analysis and includes a number of factors such as the current credit environment and the ranking of the utility segments based on business risk.

215. The UCA also argued that no adjustment for a typical level of CWIP and lower income taxes is necessary, since the credit rating agencies appeared to be satisfied with the equity ratios approved in Decision 2009-216, as evidenced by the fact that no utilities have been downgraded since 2009. However, the Commission observes that, due to a number of factors, including the impact of the financial crisis and large capital additions (where applicable), the equity ratios approved in 2009 exceeded the minimum levels indicated by the credit metric analysis in that decision by at least two percentage points.[150] Accordingly, the Commission considers that the favourable reaction of the rating agencies may be attributed to the fact that the last approved equity ratios were sufficient to account for typical amounts of CWIP, not the fact that no adjustment for CWIP was necessary.

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147 Exhibit 220.02, Utilities reply argument, paragraph 94.

148 Decision 2009-216, footnote 326 on page 94.

149 Ibid., footnotes 323 and 325.

150 In paragraph 357 of Decision 2009-216, the Commission observed that for an average Alberta utility, the equity ratio associated with the minimum credit metrics would be approximately 34 per cent (34 per cent based on the EBIT analysis, 33 per cent based on the FFO coverage analysis and 30 to 36 per cent based on the FFO/Debt analysis). Table 17 of Decision 2009-216 shows that the minimum equity ratio awarded was 36 per cent.

216. Regarding the CCA's argument that there is little risk from CWIP and that no adjustment to ROE is necessary for any amount of CWIP, the Commission reiterates that the adjustment to the credit metric calculations in regard to CWIP that was solicited through the issues list was not related to the risk of recovering CWIP balances. Rather, the issue was that CWIP mathematically lowers the credit metrics. The CCA did not address this point.

217. Consequently, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for the Alberta utilities. The Commission has considered the evidence of Ms. McShane that the median of CWIP as a percentage of total regulated assets in 2009 for the Alberta utilities was over five per cent, and finds this number to be a reasonable estimate. The Commission has reflected this level of CWIP in its updated analysis on credit metrics and associated equity ratios, presented in Table 9 below.

218. The Commission also acknowledges the Utilities' evidence that, in 2012, the combined provincial and federal statutory income tax rate will be 25 per cent, as compared to the 29 per cent used in Decision 2009-216. The Commission agrees with Ms. McShane that the income tax rate should be updated in the analysis.

219. In disputing the relevance of lower income tax rates, the UCA submitted that income taxes collected are ear-marked for payment to the tax authorities and so are not available to pay creditors. However, in the event that unforeseen expenses cause profits to decline from the forecast level, the income tax payable would decline and the cash that would otherwise go to taxes would become available to pay interest expenses. Therefore, income taxes collected are in fact partly available to pay creditors in situations where the profit, and therefore the actual amount of income tax payable, is lower than forecast. Additionally, the income tax collected would be fully available to pay interest in the circumstance where profit was zero or negative. Presumably, this is why EBIT (earnings before interest and tax) is important to credit rating agencies and debt investors, rather than simply earnings before interest.

220. However, the Commission does not accept the Utilities' recommendation of using the effective tax rate in the credit metrics analysis. The Commission agrees with the CCA's argument that, because the effective income tax rate varies greatly from utility to utility, any required adjustments should be made on a utility-specific, rather than generic basis. The Commission considers that those utilities that encounter credit rating issues because they are on the flow-through tax method can apply to adopt the future income tax method and thereby collect the full statutory income tax rate. For these reasons, the Commission will use an updated statutory income tax rate of 25 per cent in its analysis below.

221. Using an ROE of 8.75 per cent approved in this decision for 2011 and 2012, and assuming an embedded interest cost of 6.4 per cent, a depreciation rate (as a percentage of invested capital) of six per cent, a tax rate of 25 per cent, and CWIP (as a percentage of rate base) of five per cent, the Commission calculated the key credit metrics and the corresponding equity ratios as follows:

Table 9. Credit metrics compared to equity ratios – Commission analysis

	EBIT coverage[151]		FFO/Debt (%)		FFO coverage	
Equity ratio	Table 13 in Decision 2009-216	Updated and expanded assumptions	Table 14 in Decision 2009-216	Updated and expanded assumptions	Table 15 in Decision 2009-216	Updated and expanded assumptions
30%	1.8	1.7	12.32	11.73	2.90	2.79
31%	1.9	1.7	12.63	12.03	2.94	2.83
32%	1.9	1.8	12.94	12.32	2.99	2.88
33%	1.9	1.8	13.26	12.63	**3.04**	2.93
34%	**2.0**	1.8	13.60	12.95	3.09	2.98
35%	2.0	1.9	13.94	13.28	3.14	**3.03**
36%	2.1	1.9	**14.30**	13.62	3.20	3.08
37%	2.1	**2.0**	14.66	13.96	3.26	3.13
38%	2.2	2.0	15.04	**14.32**	3.31	3.19
39%	2.2	2.1	15.43	14.7	3.37	3.25
40%	2.3	2.1	15.83	15.08	3.44	3.31
41%	2.3	2.2	16.25	15.48	3.50	3.37
42%	2.4	2.2	16.68	15.89	3.57	3.43
43%	2.4	2.3	17.13	16.31	3.63	3.5
44%	2.5	2.3	17.59	16.75	3.71	3.57
45%	2.6	2.4	18.07	17.21	3.78	3.64

222. Table 9 shows that, given the Commission's assumptions, the minimum equity ratio for Alberta utilities should be 37 per cent based on the EBIT analysis, 30 to 38 per cent based on the FFO/debt analysis and 35 per cent based on the FFO interest coverage analysis. These values show that, as a result of incorporating a typical amount of CWIP and accounting for the lower level of income taxes, the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216.

223. However, as the Commission pointed out earlier in this section, due to a number of factors, including the impacts of the financial crisis and the impact of large capital additions, among others, the equity ratios approved in Decision 2009-216 somewhat exceeded the levels indicated by the credit metric analysis in that decision. In particular, Table 9 above demonstrates that by and large, the currently approved equity ratios of the Alberta utilities meet or exceed the minimum levels determined by the credit metric analysis. In light of these factors, the Commission considers that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is warranted.

151 As discussed in Exhibit 209, Attachment 2 to the Utilities argument, Ms. McShane calculated the EBIT coverage ratios using the S&P methodology, which includes the equity portion of an allowance for funds used during construction (AFUDC) in EBIT component. The Commission used the DBRS methodology, which excludes the equity portion of AFUDC from earnings, resulting in more conservative estimates. However, under the five per cent CWIP assumption, the difference between the two methods is minimal.

5.4 Ranking risk by regulated sector

224. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk affects the perceived uncertainty in future operating earnings and hence determines the capacity for a business to be financed with debt as opposed to equity.

225. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electricity distribution segment was slightly more risky than the electric transmission sector. The Commission agreed that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[152]

226. In the current proceeding, none of the expert witnesses put forward evidence which would indicate materially changed business risks for the utility sectors since Decision 2009-216, with the exception of ATCO Pipelines in light of the integration with Nova Gas Transmission Ltd. (NGTL).

227. In particular, the Utilities recommended no adjustment, generic or company specific, to capital structures due to the recognition of high levels of contributions in aid of construction (CIAC).[153] The Utilities recommended that compensation for high levels of CIAC occur by way of a management fee, as discussed in Section 6 below. The same argument was put forward by the UCA.[154]

228. As well, the Utilities pointed out that their assessment of the business risks upon which their deemed capital structure recommendations was based did not reflect consideration of the potential of changed risks associated with the implementation of a PBR regime in the near future. The Utilities reasoned that, until the specifics of the form of PBR to which any given utility becomes subject are known, a grounded assessment of changes in risk cannot be made.[155]

229. Furthermore, parties to this proceeding submitted that they were not aware of any adjustments to capital structure that would be required to accommodate growth above the historic trend. The UCA submitted that, to the extent that credit related issues have arisen in the context of mandated transmission builds by Alberta TFOs, those have been, or will be, addressed through utility specific measures like including CWIP in rate base or allowing the collection of future income taxes.[156] The Utilities supported this view.[157]

Commission findings

230. The Commission has evaluated the expert evidence of witnesses representing interested parties to this proceeding, and agrees that business risks for Alberta utilities have not changed materially since 2009, with the exception of ATCO Pipelines.

152 Decision 2009-216, paragraphs 370-371.
153 Exhibit 209, Utilities argument, paragraph 154.
154 Exhibit 210.02, UCA argument, paragraph 201.
155 Exhibit 209, Utilities argument, paragraph 155.
156 Exhibit 210.02, UCA argument, paragraph 213.
157 Exhibit 209, Utilities argument, paragraph 156.

231. Consequently, the Commission reaffirms its findings in the 2009 GCOC decision. In particular, as outlined in Decision 2009-216,[158] the Commission finds that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas.

232. The Commission findings with respect to the impact of CIAC are presented in Section 6 of this decision.

5.5 Further company-specific considerations

233. The Commission now turns to a consideration of further adjustments to the equity ratios of individual companies based on their specific business risks.

5.5.1 Adjustment for non-taxable status

234. In Decision 2009-216, the Commission affirmed the two percentage point adjustment to common equity ratios for non-taxable utilities, initially approved in Decision 2004-052, on the basis of higher earnings volatility and a negative impact on credit metrics. This adjustment applied to ENMAX and EPCOR utilities and was extended to FortisAlberta, since at the time of the 2009 GCOC decision FAI anticipated being a non-taxable entity until at least 2013.[159]

235. In this proceeding, Ms. McShane noted that, to fully reflect the impact of non-taxability on pre-tax interest coverage ratios, the common equity adjustment would need to be six per cent. Notwithstanding this, the Utilities submitted they supported the findings of the Commission and its predecessor that two percentage points increase is warranted and recommended that this adjustment for non-taxable status continue to apply.[160]

236. Ms. McShane also indicated that, based on FortisAlberta's assessment, it will collect zero income taxes in rates through at least 2016 and, therefore, FortisAlberta remained a de facto non-taxable entity for purposes of this proceeding.[161] As such, in this proceeding, each of the non-taxable utilities (ENMAX and EPCOR as legally non-taxable and FortisAlberta as de facto non-taxable) were seeking a deemed capital structure that continued the treatment established in Decision 2009-216 and Decision 2004-052.

237. The UCA submitted that the additional two per cent equity thickness that has been provided to non-taxable utilities due to their higher earnings volatility was not reasonable or necessary. Specifically, the UCA indicated that the argument regarding increased earnings volatility assumes that any variance in earnings is symmetrical when in fact over-earning is more common. Relying on the data on historical earned ROEs relative to allowed ROEs provided by the Commission in Exhibit 161, the UCA submitted that Alberta utilities are more likely to over-earn their allowed returns than to under-earn, and the benefit of the same amount of over-earning increases with a lower tax rate.[162]

158 Decision 2009-216, paragraphs 370-371.
159 Decision 2009-216, paragraphs 383-384.
160 Exhibit 209, Utilities argument, paragraph 141.
161 Exhibit 86.01, Kathleen McShane Opinion, page 32, lines 812-817.
162 Exhibit 210.02, UCA Argument, paragraphs 190-193.

238. During the hearing, Dr. Roberts provided the following explanation on this point:

> Another point I might add is that if a company
> is not taxable, and it earns, let's say, an extra million
> dollars, it gets to keep 1 million, whereas if it's taxable,
> it gets to keep less because part of it has to go to the
> Canada Revenue Agency.[163]

239. As such, the UCA argued that, in practice, non-taxable status benefits utility shareholders on average by increasing their expected effective ROE relative to the effective ROEs for taxable utilities. In light of this practical benefit, the UCA submitted that there is no need to continue providing shareholders of non-taxable utilities with an even further benefit in the form of a higher allowed equity ratio. The UCA argued that the shareholders of non-taxable utilities are already better off, in terms of their expected return, than shareholders of taxable utilities, and that effect must at least offset whatever minor volatility disadvantage is associated with non-taxable status.[164]

240. In addition, the UCA submitted that, even if the Commission were to maintain the additional two per cent equity for ENMAX and EPCOR, this adjustment should not apply to FortisAlberta which, although temporarily not paying or collecting tax, remains a taxable utility. The UCA submitted that this situation would eventually reverse and FortisAlberta was just as taxable as every other utility.[165]

241. In reply, the Utilities submitted that the document identified as Exhibit 161 contained not just data publicly filed by the Utilities as part of the AUC Rule 005 reports, but adjustments which purport to alter that data. Therefore, the Utilities argued that this document could not form an evidentiary basis for any conclusions proffered by the UCA in its argument, or reached by the Commission in its decision.[166]

Commission findings

242. The Commission acknowledges that historical ROE data provided in Exhibit 161, along with the publicly available Rule 005 numbers, contain Commission staff calculations. Indeed, recognizing this fact, the Commission invited the Utilities to comment on the numbers provided in Exhibit 161, either through supplemental filings or in argument.[167] The Utilities did not provide any comments on the data in Exhibit 161. Nevertheless, the issue of whether this document can be used as evidence in this proceeding is not germane to the Commission's determination on this matter.

243. In the Commission's view, the UCA's argument that the additional two per cent equity thickness for non-taxable utilities was not necessary fails to account for the fact that the active constraint on the minimum equity ratios is the risk tolerance of debt investors, and not equity investors. Debt investors are concerned by, and could be affected by, the downside risk of an earnings shortfall. In addition, it is equity investors and not debt investors that benefit from upside risk. This is because unlike equity investors, debt holders can not gain more than the

163 Transcript, Volume 6, page 771, lines 21 to 25.
164 Exhibit 210.02, UCA Argument, paragraph 195.
165 Ibid., paragraphs 196-199.
166 Exhibit 220.02, Utilities reply argument, paragraphs 101-104.
167 Transcript, Volume 1, page 15, line 7 to page 16, line 6.

promised interest rate, even if the company performs unusually well. For these reasons, debt investors focus on downside risk, not upside.

244. As such, the Commission reaffirms its findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios, and thereby adds to risk from the debt holder's perspective. Accordingly, the Commission will maintain the addition of the two percentage point increase to the equity ratios of income tax exempt utilities.

245. With respect to FortisAlberta, the Commission notes that it became a de facto non-taxable entity in 2006, and is expected to persist in this status at least through 2016.[168] As such, the Commission considers that this situation cannot be characterized as short run non-taxability. The Commission agrees with the UCA that eventually FortisAlberta will have the same income tax liability as any other taxable entity. However, given the expected duration of FortisAlberta's de facto non-taxable status, the Commission does not share the UCA's view that higher earnings volatility associated with non-taxability will be offset by reduced earnings volatility during the future periods over which this findings this decision will apply.

246. Therefore, in the Commission's view, it is warranted to treat FortisAlberta as a non-taxable entity for the purposes of this proceeding, since it has not collected any income taxes since 2006 and is not expected to until at least 2016. This status would change if FortisAlberta became an income tax paying entity or if the Commission were to change from the flow through method of accounting for income taxes for regulatory purposes to normalized taxes or another similar method in the future.

5.5.2 Transmission facility owners and the risk of stranded assets

247. During the hearing, the AESO suggested that ratepayers rather than utility shareholders are at risk for stranded TFO assets.[169] The Commission invited the parties to comment on whether this reality needs to be considered in the risk assessment for the TFOs.

248. The UCA submitted that the AESO's position was likely consistent with the practice in most regulatory jurisdictions and with the expectations of the Utilities. The UCA expressed its opinion that any consideration of where the burden of stranded assets should fall is likely to be fact-specific, and therefore, it would not be appropriate to consider this matter generically in the current proceeding, especially considering that it was not in the original scope.[170]

249. The Utilities expressed similar concerns with the inclusion of this matter as part of this proceeding and pointed out that to date, there have been no examples of stranded assets for either transmission or distribution utilities. The Utilities implied that the AESO's position was consistent with regulatory compact, under which tariffs should provide the opportunity to recover the costs of prudent investments in the system. As such, the Utilities submitted that the business risks of the utilities have not materially changed.[171]

250. The CCA argued for symmetry and reciprocity in the treatment of utility gains and losses. Citing portions of the Stores Block decision, the CCA stated that if gains from the sale of assets

168 Exhibit 86.01, Kathleen McShane opinion, page 32, lines 812-817.
169 Transcript, Volume 3, page 493, line 22 to page 494, line 13.
170 Exhibit 210.02, UCA argument, paragraph 214.
171 Exhibit 209, Utilities argument, paragraphs 158 and 159.

which are not used and useful are to the account of the utility shareholder, losses should also be to the account of the utility shareholder. Therefore, in the hypothetical example on the record, the CCA submitted it did not agree with the position of the AESO.[172]

Commission findings

251. As set out in Section 7 below dealing with the proposed Rider I concept, the Commission does not share the AESO's view that ratepayers, rather than utility shareholders, are at risk for stranded TFO assets. Specifically, as outlined further in this decision, the Commission considers that any stranded assets should not remain in rate base.

252. The Commission acknowledges that this finding may have certain implications for the quantum of business risks of the transmission utilities. However, as both the Utilities and the AESO[173] pointed out, to date, there have been no examples of stranded assets in Alberta. Furthermore, the Commission considers that any assessment of risk associated with the potential for stranded assets, for the purposes of adjusting capital structure, would be best dealt with on a case-specific determination when the situation arises. Therefore, the Commission will not consider this factor in its risk assessment for TFOs for the purposes of this proceeding.

5.5.3 ATCO Pipelines' system integration with NGTL

253. In September 2008, ATCO Pipelines and Nova Gas Transmission Ltd. (NGTL) reached an agreement under which the two companies would combine physical assets and offer a single suite of services to provide gas transmission service. This integration was expected to be completed on October 1, 2011. Consequently, parties to this proceeding proposed a change in ATCO Pipelines' post-integration capital structure to reflect the altered risk profile of the company.

254. In her evidence, Ms. McShane indicated that because there have been no fundamental changes in the capital markets or ATCO Pipelines' requirements for access to debt capital, there was no reason to revisit the capital structure established in Decision 2009-216.[174] Furthermore, ATCO Pipelines pointed to Decision 2010-228,[175] which provided that its common equity ratio for 2011 would not take into account post integration factors.[176] As such, ATCO Pipelines requested approval of a common equity ratio of 47 per cent for 2011, which was reflective of the 2010 approved ratio of 45 per cent and the across-the-board two percentage points increase proposed by the Utilities.

255. ATCO Pipelines further submitted that although its post-integration business risk will decrease, it will still be higher than business risk of the Alberta electric distribution utilities. This conclusion was based on the assessment of the following risk factors:[177]

- competition for both gas supply and markets, which has decreased with NGTL, but has increased with Alliance Pipelines

172 Exhibit 211, CCA argument, paragraph 42.
173 Transcript, Volume 3, page 493 lines 3 to 5.
174 Exhibit 80.01, Kathleen McShane opinion on capital structure for ATCO Pipelines, page 7, A8.
175 Decision 2010-228: ATCO Pipelines. 2010-2012 Revenue Requirement Settlement and Alberta System Integration, Application No. 1605226, Proceeding ID No. 223, May 27, 2010.
176 Decision 2010-228, paragraph 88.
177 Exhibit 208, ATCO Pipelines argument, paragraph 5.

- supply risk arising from continued decline of the Western Canada Sedimentary basin (WCSB) reserves and especially those within ATCO Pipelines' operating footprint
- construction and financing risk, due to the doubling of ATCO Pipelines' annual capital expenditures

256. As a result, ATCO Pipelines requested a 44 per cent common equity ratio for 2012, which was the mid-point between the 41 per cent common equity ratio recommended by Ms. McShane for gas and electric distribution utilities and the 47 per cent recommended common equity ratio for 2011 for ATCO Pipelines.[178] ATCO Pipelines also argued that the recommended equity ratio of 44 per cent takes into account maintenance of its creditworthiness and financial integrity, assurance that it contributes its fair share to the maintenance of the credit ratings of its parent, and the opportunity to earn an overall return commensurate with investments of comparable risk.[179]

257. Dr. Booth, testifying on behalf of CAPP, pointed out that with integration, ATCO Pipeline's revenue requirement will be paid by NGTL like any other cost of NGTL doing business and ahead of NGTL paying anything to its shareholders. Dr. Booth indicated that this arrangement was very similar to the way in which Alberta electric transmission utilities recover their system costs from the distributors via the Alberta Electric Systems Operator (AESO), and the only real question was the risk of NGTL not being able to make those payments.[180]

258. In that regard, CAPP's witness noted that the combined ATCO Pipelines and NGTL systems sit on top of vast natural gas resources that will provide gas for many decades to come. Based on his analysis of available reports and forecasts, Dr. Booth noted that unconventional supplies will dramatically impact total production from the WCSB, where the growth in Horn River and Montney supply will offset the decline in conventional production.[181] As a result, CAPP argued that with these new supplies, ATCO Pipelines' supply risk has significantly reduced.

259. CAPP also submitted that ATCO Pipelines' competition risk was significantly reduced post integration, since the impact of any successful competition by Alliance Pipelines was no longer borne by ATCO Pipelines by itself, but rather by the combined ATCO Pipelines/NGTL system. Based on the above considerations, CAPP concluded that ATCO Pipelines' risk of not receiving its revenue requirement was no higher than that of Alberta TFOs and recommended that the Commission use a similar common equity ratio of 35 per cent for ATCO Pipelines in 2012.[182]

260. Mr. Marcus, testifying for the UCA, submitted that competitive and market risks will no longer be present for ATCO Pipelines post-integration. Therefore, Mr. Marcus stated that ATCO Pipelines will be similar in risk to an electric transmission utility, which receives fixed payments for services from the AESO.[183] Given this analysis, Drs. Kryzanowski and Roberts recommended a common equity ratio of 42 per cent for 2011, unchanged from their recommendation made in

178 Exhibit 80.01, Kathleen McShane opinion on capital structure for ATCO Pipelines, page 18, A21.
179 Exhibit 208, ATCO Pipelines argument, paragraph 6.
180 Exhibit 78.02, evidence of Laurence D. Booth, paragraph 205.
181 Ibid., paragraph 208; Exhibit 207.02, paragraphs 94-95.
182 Exhibit 207.02, CAPP argument, paragraph 97.
183 Exhibit 81.04, prepared testimony of Mr. William B. Marcus, page 13, lines 3-10.

2009. For 2012, they recommended a common equity ratio of 30 per cent, due to the elimination of competition with NGTL.[184]

261. The CCA also expressed its opinion that ATCO Pipelines faces significant reductions to its business risks after integration and indicated that the company will be in danger of not recovering its revenue requirement only in the case of a default by NGTL. With respect to the competition from Alliance Pipelines, the CCA submitted that this risk may not materialize within the test years of this proceeding.[185]

262. As a result, the CCA argued that ATCO Pipelines' risks are no different from the risks faced by NGTL and recommended the equity thickness of 40 per cent in 2012, as awarded to NGTL by the National Energy Board. For 2011, the CCA recommended an equity ratio of 42 per cent, which is a weighted capital structure of 75 per cent pre-integration and 25 per cent post-integration, based on October 1, 2011 as the integration effective date.

Commission findings

263. In Decision 2010-228, dealing with ATCO Pipelines' 2010-2012 revenue requirement settlement and system integration, the Commission accepted the approach proposed by the parties to that proceeding and agreed that ATCO Pipelines' equity ratio for 2010 and 2011 will exclude the impact of integration, while 2012 shall take integration into account.[186] Therefore, the Commission will base its determinations on ATCO Pipelines' 2011 common equity ratio taking into account any across-the-board adjustments applicable to all utilities, but without considering the impact of integration.

264. Furthermore, in Decision 2010-228 the Commission explained that post integration, ATCO Pipelines will collect its Commission approved revenue requirement through a monthly charge to NGTL, the ATCO Pipelines (AP) Charge. NGTL's revenue requirement, including the AP Charge, will be collected from customers using the combined regulated ATCO Pipelines and NGTL gas transmission systems, the Alberta System. Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.[187]

265. All parties to this proceeding acknowledged that with this arrangement, the only risk of ATCO Pipelines not recovering its revenue requirement is if NGTL was unable to make its payments. As such, the Commission considers that in 2012, the business risks faced by ATCO Pipelines have been significantly reduced through its integration with NGTL.

266. The UCA and CAPP witnesses argued that the business risk of ATCO Pipelines post integration is comparable to the risk of Alberta TFOs, which recover their revenue from the AESO. However, the Commission considers that this comparison is not entirely accurate. Unlike the AESO, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks (as presented in the Utilities' argument), which should be taken into account.

267. In light of the above considerations, the Commission finds that ATCO Pipelines' post integration business risk is higher than the level of risk faced by the electric transmission sector,

[184] Exhibit 210.02, UCA argument, paragraphs 202-204.
[185] Exhibit 211, CCA argument, paragraph 55.
[186] Decision 2010-228, paragraph 91.
[187] Ibid., paragraph 115.

but is somewhat lower than the risk of electric and gas distribution sectors. The Commission's determination on ATCO Pipelines' capital structure for 2012 presented in Section 5.6 below reflects these findings by setting the equity ratio at the average of those two sectors.

268. The Commission does not consider that this determination will have a significant impact on ATCO Pipelines' credit metrics. In the Commission's view, setting the equity ratio for ATCO Pipelines at the midpoint of that of the TFOs and the distribution utilities will be sufficient to attain the minimum credit metrics associated with credit ratings in the A range. This follows logically because the Commission will award equity ratios to those two sectors designed to achieve A ratings and the Commission has found that ATCO Pipelines' risk is midway between the risk of those two sectors. Furthermore, the Commission considers that if, after assessing the impacts of this decision, ATCO Pipelines remains concerned about its credit metrics, this matter can be addressed at the time of its next GTA.

5.5.4 Additional concerns raised by the UCA

269. As discussed in sections above, the UCA based its recommendations on the capital structures for the Alberta utilities based on Drs. Kryzanowski and Roberts opinion that:

- a two percentage point reduction was justified as credit markets have normalized
- the two percentage point increase awarded to the non-taxable utilities should be removed
- consideration of CWIP and lower tax rate in the credit metric analysis was not necessary

270. The Commission dealt with these recommendations in the sections above. In addition to these recommendation, Drs. Kryzanowski and Roberts suggested further reductions to equity ratios awarded in 2009 decision for certain utilities.

271. In particular, the UCA witnesses recommended that ENMAX TFO's equity ratio be set at 30 per cent, which is three percentage points lower than the EPCOR TFO's common equity ratio. The basis for Drs. Kryzanowski and Roberts' recommendation was that ENMAX Transmission had lower asset growth as compared to other TFOs in the province, and as such, its business risk (in particular, the asset replacement risk) was lower.[188]

272. Additionally, Drs. Kryzanowski and Roberts recommended differentiating the common equity ratios of ATCO Electric TFO and AltaLink. According to the UCA witnesses' calculations, taking into account the relief measures provided in Decision 2011-134,[189] a 34 per cent equity ratio was sufficient to maintain ATCO Electric's credit metrics above the minimum levels.[190]

273. Drs. Kryzanowski and Roberts also recommended that the equity ratio for ATCO Gas be set at 34 per cent, which was one percentage point lower than their suggested equity ratio for

188 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, page 81.

189 Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.

190 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraphs 139-143.

electric distribution companies. The UCA witnesses indicated that the lower ratio for ATCO Gas reflects the reduction in business risk from its weather deferral account.[191]

274. Finally, the UCA pointed out that Drs. Kryzanowski and Roberts recommended a 90 basis point flexibility adjustment to the allowed return on equity to further ensure that the utilities are capable of maintaining a credit rating in the A range.

275. The Utilities argued that there was no legitimate basis for distinguishing between the capital structures of ENMAX and EPCOR TFOs. As well, the Utilities submitted that the evidence in this proceeding did not support the view that ATCO Electric TFO and AltaLink should have different common equity ratios on a generic basis. The Utilities submitted that both of these proposals violated the standalone principle. In addition, the Utilities argued that any individual differences among the awarded common equity ratios should be made on company specific basis as part of the GTA process, and not during the GCOC process.

Commission findings

276. The approach of UCA and Drs. Kryzanowski and Roberts of adding 90 basis points to a common ROE in support of credit metrics presents some difficulties for the Commission.

277. In Decision 2004-052, the Commission's predecessor applied a generic ROE to all utilities and addressed the need for any utility-specific adjustments to the common ROE through the capital structure. Moreover, the board indicated 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 utility.[192]

278. In Decision 2009-216, the Commission reiterated that it will adjust for any differences in risk among the utilities by adjusting their individual equity ratios.[193] The Commission has reaffirmed its adherence to this approach in this decision as well. As such, the UCA's approach to add 90 basis points to the ROE on order to support an A category credit rating contradicts the approach taken by the Commission.

279. Additionally, the UCA's proposal makes it difficult to compare its recommendations to those of the other participants or even to the 2009 GCOC decision. In order to assess the UCA's ROE recommendation on a comparable basis, one could perhaps deduct the 90 basis points adder. But this was not the position of the UCA and so the Commission does not favour this approach. Besides, if the Commission were to deduct the 90 basis points from the UCA's ROE recommendation, it is not clear what amount, if any, should be added to the UCA's equity ratio recommendations. Furthermore, the UCA did not present any analysis to show that an adder to the ROE was a more cost effective way to support an A range credit rating than adjusting to a higher equity ratio.

280. Given these considerations, the Commission has evaluated the UCA's ROE and equity ratio recommendations as if they were independent of each other.

281. The UCA's credit metric analysis and resulting recommendations on the common equity ratios for the Alberta utilities were based on the assumptions that CWIP and lower income tax

191 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 414.
192 Decision 2004-052, pages 14 and 15.
193 Decision 2009-216, paragraph 78 and 221.

rates are not included in the credit metric calculations.[194] As detailed in Section 5.3.2 above, the Commission did not agree with this premise.

282. Furthermore, the UCA's approach of differentiating capital structures of ENMAX and EPCOR TFOs, ATCO Electric and AltaLink TFOs, as well as further distinguishing between the capital structures of ATCO Gas and AltaGas, runs contrary to the Commission findings in Section 5.4 above and the UCA's own evidence that business risks have not materially changed since 2009.[195]

283. For example, the UCA indicated that its recommended equity ratio for ATCO Gas of 34 per cent was one percentage point lower than equity ratio of electric distribution companies due to the reduction in business risk from its weather deferral account. However, the Commission already considered this matter when determining the common equity ratios in 2009. As presented in Decision 2009-216, the Commission acknowledged the existence of the weather deferral account and determined that that ATCO Gas has a similar level of business risk compared to electric distribution companies.[196]

284. More importantly, Drs. Kryzanowski and Roberts acknowledged that their proposed equity ratios for ENMAX Transmission and ATCO Pipelines (in 2012), were inconsistent with the minimum equity ratios observed by the Commission.[197]

285. For these reasons, the Commission does not accept the UCA's recommendations regarding further reductions in equity ratios for ATCO Electric and ENMAX TFOs, as well as ATCO Gas.

5.6 Conclusion regarding required capital structures

286. The Commission has examined a number of factors that are relevant to determining the required equity ratios. These include a consideration of the recent developments in credit environment, the levels of key credit metrics that are associated with the actual credit ratings of relatively pure-play Canadian utilities, and certain utility-specific adjustments.

287. Two factors that could potentially impact the electric transmission sector were also examined; the impact of above historic trend growth and any risk associated with the potential for stranded transmission assets. Finally, several other factors specific to certain individual utilities were examined. These included the non-taxable status of a number of the utilities, the competitive situation facing ATCO Pipelines following its integration with NGTL, and differentiation of equity ratios among certain utilities as proposed by the UCA.

288. Accordingly, the Commission makes the following findings:

1. There is no need to reverse the adjustment to the Alberta utilities' capital structure that was provided in Decision 2009-216 to account for the financial crisis, because the effects of the financial crisis have not completely abated.

[194] Exhibit 210.02, UCA argument, paragraph 222.
[195] Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraphs 238 and 286.
[196] Decision 2009-216, paragraphs 368, 371 and 412.
[197] Ibid., paragraph 221.

2. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta utilities should be 37 per cent based on EBIT analysis, 30 to 38 per cent based on FFO/debt analysis and 35 per cent based on FFO interest coverage analysis; (ii) the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216, however (iii) since the equity ratios approved in the 2009 GCOC decision meet or exceed the minimum levels recommended above, no across-the-board increase to the currently approved equity ratios for the Alberta utilities is required.

3. The business risk analysis does not indicate that there have been major changes in the relative risks of the various utilities segments, with the exception of ATCO Pipelines following its integration with NGTL. Hence, as in the case of the 2009 decision, any increase in equity ratios should be relatively uniform across the sectors and individual utilities unless utility-specific considerations require otherwise.

289. Given the Commission determinations with respect to the effects of the financial crisis, the results of the credit metric analysis, and the Commission's finding that the relative risks of the various utilities segments have not changed, the Commission finds that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is necessary.

290. The Commission will now consider the need for any company-specific adjustments to equity ratios.

ATCO Electric and AltaLink TFOs

291. As discussed earlier in this decision, recognizing the need to mitigate the impacts of the large capital build on ATCO Electric TFO and AltaLink TFO credit metrics, the Commission recently approved relief measures for these two companies in Decision 2011-134 and Decision 2011-453, respectively. These measures included the suspension of the current accounting treatment for CWIP (also known as CWIP in rate base) and approval for the future income tax method.

292. However, the credit metric relief packages approved for these transmission companies were based on the 2009-2010 approved ROE level of nine per cent, not the 8.75 per cent ROE approved in this decision for 2011 and 2012. With this reduction in the level of allowed return, the Commission considers that these two TFOs will not be afforded the level of relief intended in those decisions. In order to maintain the level of relief intended in Decision 2011-134 and Decision 2011-453, the Commission awards a one percentage point equity increase in the capital structure of ATCO Electric TFO and AltaLink TFO.

ATCO Pipelines

293. As detailed in Section 5.5.3 above, ATCO Pipelines' equity ratio for 2011 would be reflective of any common adjustments applicable to all utilities, but without considering the impact of integration. Therefore, ATCO Pipelines is awarded a 45 per cent equity ratio for 2011, unchanged from its currently approved level.

294. In 2012, ATCO Pipelines' equity ratio is set at 38 per cent, which represents the mid-point between the awarded equity ratios for the electric transmission and electric distribution sectors (without considering the extra adjustment for the tax-exempt utilities).

Table 10. Equity ratio findings

	Last approved (%)	2011 approved (%)	Change in approved common equity ratio (%)
Electric and Gas Transmission			
ATCO Electric TFO	36	37	1
AltaLink	36	37	1
ENMAX TFO	37	37	no change
EPCOR TFO	37	37	no change
RED Deer TFO	37	37	no change
Lethbridge TFO	37	37	no change
TransAlta	36	36	no change
ATCO Pipelines	45	45 for 2011 38 for 2012	no change for 2011 (7) for 2012
Electric and Gas Distribution			
ATCO Electric DISCO	39	39	no change
ENMAX DISCO	41	41	no change
EPCOR DISCO	41	41	no change
ATCO Gas	39	39	no change
FortisAlberta	41	41	no change
AltaGas	43	43	no change

5.7 Future adjustments to capital structure

295. The equity ratios awarded in this proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

6 Management fee matters

6.1 Background

296. The Utilities proposed a management fee as compensation for the provision of service involving assets funded by customer contributions in aid of construction (CIAC). The concept of a management fee had been previously proposed by ATCO Electric in its 2009-2010 General Tariff Application (Proceeding ID No. 86) and AltaLink in its 2009-2010 TFO Tariff Application (Proceeding ID No. 102). The proposed management fee applied for in those applications was intended to provide compensation for the risks and value of service associated with ownership, operation and maintenance of assets financed by CIAC. In Decision 2009-087[198] in respect of ATCO Electric's 2010-2011 General Tariff Application, the Commission stated:

> The Commission finds that consideration and evaluation of CIAC and related compensation to the utility could be more efficiently and effectively addressed going forward at a generic proceeding, which would allow for a more detailed review of all

[198] Decision 2009-087: ATCO Electric Ltd., 2009-2012 General Tariff Application – Phase I, Application No. 1578371, Proceeding ID. 86, July 2, 2009.

relevant issues at one time by all potentially affected parties. The Commission will advise all parties in the near future as to the process that will be established.[199]

297. The Commission issued a similar finding in Decision 2009-151[200] in respect of AltaLink's 2009-2010 TFO Tariff Application.

298. By letter dated December 16, 2010, the Commission determined that the consideration of a management fee would be included in the scope of this proceeding.

299. The Utilities engaged Ms. McShane to assist in developing its position in respect of the proposed management fee. Ms. McShane provided the following conclusions in her evidence in respect of the proposed management fee:

- The proportion of CIAC to total regulated assets for the Alberta Utilities in the composite is materially higher than for the typical non-Alberta utility.
- CIAC relates to assets that are constructed, owned, managed and operated by the utilities, but for which no compensation in the form of return, margin or fee is provided, despite the fact that the utilities bear risks related to them.
- The root cause of the size of the CIAC is the existing investment and contribution policies. Amending investment policies is required but the mitigation will only occur over time and the Alberta Utilities should be afforded compensation for services rendered with respect to facilities funded in whole or in part by CIAC.
- The approach adopted to determine the amount of compensation that is reasonable for CIAC funded assets has been derived from the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC. The compensation determined from this analysis, estimated as a return on CIAC, is two per cent. For taxable utilities the two per cent margin needs to be grossed up for income taxes to allow the utilities to earn the two per cent margin on an after-tax basis. The two per cent estimated return is supported by applying the approach used in the past by the Ontario Energy Board (OEB) to derive a reasonable return for deferred tax balances.
- The proposed two per cent return would be applied to CIAC balances that exceed four per cent of total rate base, inclusive of CIAC. The four per cent threshold was based on the average contributions as a per cent of gross rate base for nine non-Alberta regulated utilities as provided in Table 1 of Ms. McShane's evidence.
- The existing capital structures and ROE's, which were awarded in the absence of any consideration of CIAC, do not provide any compensation for CIAC.[201]

300. Ms. McShane stated that, in the absence of significant rate base upon which to determine a reasonable return, regulators have adopted alternative methodologies to provide a measure of return to the regulated utilities and noted the following examples:

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199 Decision 2009-087, paragraph 38.

200 Decision 2009-151: AltaLink Management Ltd. And TransAlta Corporation, 2009 and 2010 Transmission Facility Owner Tariffs, Application No. 1587092 and Application No. 1594573, Proceeding ID. 102, October 2, 2009.

201 Exhibit 86.01, opinion on management fee and Rider I, lines 27-73.

- The Commission and its predecessors have adopted the concept of a return margin in the case of regulated rate tariffs where there is little rate base.
- The Independent Assessment Team[202] recommended the adoption of a minimum return margin in respect of the power purchase agreements related to the heritage electricity generation plants to address the issue of rising operating leverage as the generating plants reached the end of their accounting lives.
- The Federal Energy Regulatory Commission (FERC) adopted a management fee in cases of pipelines that are largely depreciated.[203]

301. Ms. McShane stated that the point of departure for the recommended approach is the recognition that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC) the higher is the financial risk. Ms. McShane noted that operating leverage referred to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[204]

302. The Utilities' management fee proposal centered, however, on the issue that CIAC relates to assets that are constructed, owned, managed and operated by the Utilities, but for which no compensation in the form of return, margin or fee is provided despite the fact that the Utilities bear risks related to these assets and use them to provide valuable services.[205]

303. Conceptually, the management fee proposed by the Utilities involves a fee that would be included in the revenue requirement calculated as two per cent of each utility's remaining unamortized CIAC balance in excess of four per cent of its total assets. The Utilities summarized the calculation of the annual management fee in their argument as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilities would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[206]

304. The UCA engaged Mr. William B. Marcus to assist in developing its position in respect of the proposed management fee, among other things. Mr. Marcus, in his evidence, submitted that he is opposed to the proposed management fee for the following reasons:[207]

202 The Independent Assessment Team (IAT) was appointed under provisions included in April 1998 amendments to the *Electric Utilities Act*. The scope and duties of the IAT were set out in the *Electric Utilities Act*, and were focused on two major areas: assessment and determination of the PPAs, and design of the auction process (see Decision U99073: Board Review of the Independent Assessment Team's Report on Power Purchase Arrangements and other Determinations (Issued: August 30, 1999)).

203 Exhibit 86.01, opinion on management fee and Rider I, lines 234-265.

204 Exhibit 86.01, opinion on management fee and Rider I, lines 361 to 366.

205 Exhibit 86.01, opinion on management fee and Rider I, lines 216-224.

206 Exhibit 209.01, Utilities argument, paragraph 260.

207 Exhibit 81.04, prepared testimony Mr. William B. Marcus, pages 43 and 44.

- It upsets the regulatory compact, where a utility earns a return on invested capital commensurate with the company's business and financial risk, by providing a return on capital that the utility does not actually invest, even though the business and financial risks of the entire company – including contributed property –have already been considered when setting the capital structure and return on equity.
- The proposal made by utilities in the past completely negates the purpose of CIAC by forcing ratepayers to pay the same equity return on contributed property as they would pay had the utility simply put everything in rate base and had no contribution policy at all. All that is saved is the cost of debt.
- Giving shareholders an equity return on contributions without requiring them to actually invest any equity will enrich shareholders far more than if contributions were simply abolished. This comparison shows that paying an equity return on contributions will provide shareholders with an outsized and unreasonable return.
- What is actually being "managed" for contributed property is O&M expense. These expenses and the cost and risk of managing these expenses are included in rates, and the increase in contributions has not resulted in a significant increase in the utilities' total business risk.
- A management fee for contributions is a solution in search of a problem. Alberta has had high levels of distribution contributions literally for decades. Contributed transmission property has increased somewhat in recent years but is still on the order of 10 per cent of total transmission assets. Many of those assets are in fact contributed by the distribution company.

305. By letter dated August 5, 2011 the Commission set out a final issues list for argument and reply. The management fee section of this decision addresses the issues in respect of the proposed management fee as set out in Attachment 1 to the Commission's August 5, 2011 letter.

6.2 Views of the parties

6.2.1 Is a management fee compatible with the fair return standard and the paradigm of paying a return on capital invested in rate base?

306. The Utilities argued that the proposed management fee provides the utilities with fair compensation for providing valuable services and bearing the risks associated with the construction, ownership, operation and management of CIAC-financed assets and submitted that parties objecting to the management fee have ignored the unfairness arising from the utilities' obligation to provide services in relation to CIAC-financed assets for no compensation.

307. The Utilities also argued that the management fee is compatible with the legal framework as well as the fair return standard and that it provides for fair compensation for utility services rendered. Finally, the utilities stated that the management fee constitutes a fee or a just and reasonable charge for service rather than a fair return, which is legally separate and compensates the utility for something different. The Utilities stated that the two concepts, though independent of each other, are complementary.[208]

[208] Exhibit 209.01, Utilities argument, paragraphs 162 to 165.

308. The UCA submitted that the type of management fee proposed by Ms. McShane on behalf of the Utilities is not consistent with the fair return standard or the paradigm of paying a return on capital invested in rate base. The paradigm is cost-based rates, the UCA submitted, under which utilities are permitted to charge rates that will give them a reasonable opportunity to recover their prudently incurred costs, including the cost of the debt and equity capital they have invested in the business.[209]

309. The UCA argued that CIAC collected from customers by the Utilities represents capital that has been invested by the Utilities that has no cost associated with it. By effectively allowing shareholders to earn a return on the no-cost capital contributed by third parties, the UCA submitted, the management fee proposed by the Utilities would enable the Utilities, and ultimately their shareholders, to earn amounts in excess of their costs, including a fair return on the equity capital that has been invested by shareholders.[210]

310. The CCA agreed with Mr. Marcus and submitted that a management fee is incompatible with a fair return standard on invested capital. The CCA considered that the use of a management fee and a fair return on rate base and construction work in progress, or plant held for future use, results in excessive returns to the utility. The CCA also agreed with Mr. Marcus that a management fee is inconsistent with cost-based rate-making principles and it is inappropriate to award a utility a return, in the form of either a return on investment or a management fee, on the assets financed by customers.[211]

311. IPCAA submitted that the Utilities are asking to be compensated as if they had invested in the customer contributed facilities they are managing. Where facilities have been paid for by customers through customer contributions, rather than by the utility, IPCAA submitted that there is no equity injection by the utility and no concomitant risk accompanying such an investment. IPCAA submitted that the management fee proposal before the Commission is incompatible with the fair return standard and the paradigm of paying a return on capital invested in rate base.[212]

312. IPCAA submitted in reply argument that the Utilities receive cost of service compensation for the operation, maintenance and 'management' of CIAC-financed assets, so the Utilities statement in argument that "the Utilities receive no compensation relating to CIAC-financed assets" is incorrect and that compensation may or may not include a profit component. The Utilities, IPCAA submitted, as with all utilities in Alberta (and almost all of North America) are regulated on a cost of service basis and receive recovery of all reasonably incurred costs for services rendered. The Utilities receive such compensation for all CIAC assets, IPCAA argued, and no other form of compensation is warranted or indeed permitted.[213]

313. IPCAA noted that the Utilities themselves state, with respect to the risk of stranded TFO assets, that "the regulatory compact in Alberta has been such that tariffs are to, and do, provide the opportunity to recover the costs of prudent investments in the system." IPCAA stated that the Utilities make IPCAA's point; that there is nothing in the regulatory compact which allows a utility to recover compensation over and above its prudent costs of services provided. Profit is

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209 Exhibit 210.02, UCA argument, paragraph 232.
210 Exhibit 210.02, UCA argument, paragraph 232.
211 Exhibit 211.01, CCA argument, paragraph 59.
212 Exhibit 212.01, IPCAA argument, paragraph 17 and 18.
213 Exhibit 222.01, IPCAA reply argument, paragraph 2.

possible on investments, just as the Utilities note, and only on investments. IPCAA submitted that utility investment has always been net of CIAC investment.[214]

314. IPCAA stated that services such as providing operations and maintenance services have been paid by the cost recovery of operation and maintenance expenses, excluding a profit component. All the items of allowable costs are set out in Section 122(1) of the *Electric Utilities Act.* This reflects the regulatory compact as it exists in Alberta, and it is this compact that the Utilities appear to want to defend on the one hand (with respect to the risk of stranded TFO assets) and undermine on the other hand (in the context of a management fee).[215]

315. CAPP submitted that the Utilities argument that a management fee is separate from the fair equity return to be allowed the equity investor is paradoxical since the management fee is nothing more or less than compensation to the equity investor. It is the equity investor that is the intended recipient of the fee and the result is to increase the return to the equity investor. CAPP submitted that gas utilities like ATCO Pipelines have been collecting customer contributions for decades without it ever being suggested that the equity investor was being short changed. If utility equity investors were being short changed all these many decades it would have been evident in market data long before now.[216]

316. In reply, the Utilities countered the assertions made by IPCAA and CAPP that the Utilities are compensated for costs incurred in respect of CIAC assets by stating that mere cost recovery is not compensation for valuable services rendered. The Utilities agreed that, where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities noted that CAIC levels are significantly higher in Alberta than the industry average and, as a result, the paradigm does not provide fair compensation, or any compensation, in relation to services provided and risks borne in relation to CIAC-funded assets. The Utilities reiterated that the proposed management fee augments the conventional model, it does not supplant it.[217]

6.2.2 Does the Commission have the jurisdiction under its governing legislation to provide for a management fee?

317. The Utilities argued that the proposed management fee addresses a fundamental issue of fairness and that, consistent with the fundamental principles of utility regulation and the regulatory compact, regulated entities should not be expected to provide service to customers for zero compensation.[218] Consequently, the Utilities asserted that they should be fairly compensated for the risks undertaken and the services provided to ratepayers using CIAC-financed assets.

318. With regard to the Commission's jurisdiction to award a management fee, the Utilities referred to sections 121(2) and 122(1) of the *Electric Utilities Act as* establishing the basis for a utility to recover costs and expenses associated with the provision of necessary services to customers.

319. The Utilities argued that CIAC assets are indistinguishable from other utility assets and so the Utilities should be provided an opportunity to earn fair compensation for services the

214 Exhibit 222.01, IPCAA reply argument, paragraph 3.
215 Exhibit 222.01, IPCAA reply argument, paragraph 4.
216 Exhibit 217.02, CAPP reply argument, paragraphs 19, 20, and 21.
217 Exhibit 220.02, Utilities reply argument, paragraphs 109-111.
218 Exhibit 209.01, Utilities argument, paragraph 163.

Utilities are mandated to provide using CIAC-financed assets. The Utilities stated that the Commission should approve the management fee consistent with the Commission's statutory obligation to provide just and reasonable compensation per Section 121(2)(a) of the *Electric Utilities Act.*

320. With respect to gas utility-related legislation, the Utilities cited Section 4(3) of the *Roles, Relationships and Responsibilities Regulation* as the basis for a gas utility's recovery of costs and expenses associated with the provision of necessary services to customers and stated that sections 36(a) and 45 of the *Gas Utilities Act* contemplate that regulated utilities will receive reasonable compensation for the services they provide.

321. The Utilities took issue with the interveners' characterization of the management fee as a return on monies not invested, stating that the Utilities are instead requesting fair compensation in the form of a separate fee or just and reasonable charge commensurate with the value of services rendered that is distinguishable from fair return.

322. The Utilities argued that the right to be fairly compensated for services provided to ratepayers through the use of utility assets is a fundamental underpinning of the regulation of utilities, and has been previously recognized by the Courts. In contrast to the position of interveners, the Utilities argued the presence of cost of service references in the legislation does not preclude the Commission from awarding a management fee.

323. Even in the absence of any statutory provision, the Utilities stated that consumers would have imposed upon them an obligation at common law to pay for the service on the basis of *quantum meruit,* as part of the undoubted jurisdiction to ensure that tolls are at all times just and reasonable. In support of this, the Utilities cited the Supreme Court of Canada's decision in *City of Edmonton et al. v. Northwestern Utilities Ltd*:[219]

> The right of the consumers to require the respondent to supply them with gas, conferred by the statute, would, in my opinion, <u>even in the absence of any statutory provision, impose upon them an obligation at common law to pay for the service on the basis of quantum meruit</u>. In such circumstances, I consider that the position of the utility would be similar to that of a common carrier upon whom is imposed, as a matter of law, the duty of transporting goods tendered to him for carriage at fair and reasonable rates. (Great Western R. Co. v. Sutton (1869), L.R. 4 H.L. 226 at 237). Here the duty of determining what rates are fair and reasonable is imposed upon the board.(…) [Emphasis added.]

324. The Utilities cited *Sullivan on the Construction of Statutes* to support the position that there exists a presumption that legislation is not intended to alter the common law but that the common law is meant to be incorporated. Absent clear legislative intent to the contrary, the Utilities argued, a utility has the right to receive just and reasonable compensation for providing services that it is legally obligated to provide.

325. Accordingly, the Utilities stated that:

> (E)ven if one were to ignore the provisions of applicable legislation, which provide for fair compensation for utility services rendered and obligate the Commission to ensure

219 *City of Edmonton et al. v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at 401(*Northwestern 1961*).

> that tariffs are just and reasonable, the Utilities are entitled to fair compensation based on principles of *quantum meruit*, for value of service rendered. Yet, the current treatment of CIAC does not provide any compensation to the Utility, let alone fair compensation dictated by the common law principles of *quantum meruit*, which is also encompassed in the legislative requirement that rates be just and reasonable.[220] [footnotes omitted]

326. In response to the question of whether the Commission has the jurisdiction under its governing legislation to provide for a management fee, the UCA noted that the general approach of limiting utility rates to a cost-based level has been developed and applied by North American utility regulators, including the Commission, for some time. The UCA stated that, in many jurisdictions, the governing statutory requirement is simply that rates be just and reasonable, and not unjustly or unduly discriminatory. In those jurisdictions, the UCA submitted, the legislature has left the determination and definition of the "just and reasonable" standard to the regulators.

327. The UCA distinguished the situation in Alberta, where it argued that the legislature has gone further and codified a requirement for conventionally determined cost-based rates in the relevant statutes. The UCA noted that, under Section 90 of the *Public Utilities Act*, in order to fix just and reasonable rates, the Commission is required to determine a rate base for the property of the owner of the public utility that is used or required to be used to provide service to the public, and fix a fair return on that rate base. The UCA also cited Section 122 of the *Electric Utilities Act* which states that, when considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of the electric utility with a reasonable opportunity to recover the costs and expenses associated with the capital related to the owner's investment, including a fair return on the equity of shareholders of the utility as it relates to the investment.

328. The UCA argued that conventionally determined cost-based utility rates are not only just and reasonable, as a matter of economic and regulatory theory, but are therefore also required by the relevant Alberta statutes. To the extent a management fee would enable the utilities to recover, on an expected basis, amounts in excess of their costs, including a fair return on equity, the UCA submitted that such a fee is not permitted by the statutes.

329. The UCA also noted the Utilities' argument that the principle of *quantum meruit* operates, notwithstanding the provisions of the *Electric Utilities Act* and *Gas Utilities Act*, to give the Utilities a common law or equitable right to compensation for the value of services provided using CIAC-financed facilities in addition to their statutory right to charge rates that enable them to recover their costs, including a fair return.

330. The *quantum meruit* principle, the UCA submitted, is an equitable doctrine that enables the Courts, based on specific factual circumstances, to award compensation for services rendered in situations where the person providing the service should be entitled to receive some level of compensation on "equitable grounds" and is not entitled to any compensation under contract, statute, or on other legal grounds. The UCA argued that the Utilities do not provide any services that they are not compensated for, and the compensation they receive is set at a level that meets the requirements of the applicable statutes. Thus, the UCA submitted, there are no uncompensated-for services for the *quantum meruit* principle to apply to.

220 Exhibit 209.01, Utilities argument, paragraph 176.

331. The UCA took issue with the notion that the Utilities appeared to be suggesting that the *quantum meruit* principle applies not just to whether they receive compensation for services they provide, but to the level of that compensation. The UCA argued that to claim that the principle provides for a common law or equitable right to require the Commission to set rates at a level that is higher than a cost-based level, if the value of the services provided by the Utilities exceeds the cost of providing them, is inconsistent with the *Electric Utilities Act* and the *Gas Utilities Act* as well as the *Northwestern* decision and cannot be correct.

332. Approval of the management fee proposal would, the UCA argued, result in rates that are higher than are necessary to enable the Utilities to recover their prudently incurred costs, including a fair return. It would also, the UCA argued, result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable under any normal conception of that expression.

333. The CCA submitted that a management fee and return on invested capital results in excessive returns to the utility and that the awarding of an excessive return in the form of a management fee and return on invested capital is beyond the AUC's jurisdiction.

334. IPCAA submitted that the Commission did not have the jurisdiction to award the management fee in the form requested by the Utilities, as such a fee would only be justified if the Utilities had made an equity injection with respect to the subject facilities. IPCCA argued that Section 122(1) of the *Electric Utilities Act* did not support the Utilities' proposal as the Utilities already received cost recovery under those provisions. IPCAA argued that the management fee as proposed would grant recovery over and above the costs and expenses incurred by the Utilities in managing these facilities and that is not permitted under Section 122. IPCAA also disagreed with the Utilities' argument that the Commission "should approve the Management Fee, consistent with the Commission's statutory obligation to provide just and reasonable compensation per section 121(2)(a) of the *EUA*," stating that Section 121 was a general section, the type seen in virtually all similar statues.

335. IPCCA stated that the Utilities' arguments that "compensation commensurate with value of service rendered is a common law right" and that "regulated entities have never been expected to provide service to customers for no compensation" ignore both the compensation the Utilities receive for 'managing' CIAC assets and the law. IPCAA submitted that the regulatory compact, as reflected in the *Electric Utilities Act*, compensates utilities for services performed on the basis of the cost of service model and that, conversely, return of and on equity is precisely that; namely, return on the equity component of capital invested by the utility, and no more profit beyond that.

336. Arguing that the Utilities' statement that the "net rate base model focuses solely on the concept of cost of service, with no consideration given to the value of the services provided" is misleading, IPCAA submitted that it was more accurate to say that the cost of service model is used as a proxy for the value of services rendered by a utility.

337. IPCCA also argued that the Utilities' management fee proposal runs contrary to the regulatory compact and could equally apply to all other costs incurred by utilities in providing service. As an example, IPCCA noted that the cost of debt has always been recovered on a cost of service basis with no component for profit. If the Utilities' "illogic" was followed, IPCAA

argued, then investment covered by debt is also a "valuable service" and should be entitled to a profit in addition to the recovery of debt costs.

338. CAPP submitted that utility investors are allowed a return of and on their investment and that the law does not allow utility investors to get a return on money they have not put into the business. CAPP argued that the modern regulatory statute completely replaces the common law with regard to payment for utility services. The fair and reasonable compensation for common carriers under common law spoken of by Justice Locke in *Northwestern 1961*, CAPP argued, is now not a matter of *quantum meruit* as that may be measured by a judge in a civil action, but is to be determined in accordance with the principles established by statute by expert regulatory commissions.

339. The rate of return/rate base model is the law in Alberta, CAPP argued, which means equity investors earn a return on their equity investment, while debt investors earn a return on their debt investment. CAPP noted that the equity investor does not get a return for the management of the assets funded by debt: neither does the debt investor get a return for the management of the assets funded by equity. Likewise, CAPP argued, neither the law nor the model allows for a return on money that comes cost free from the customer. CAAP submitted that there is no unfairness in that, just as there is no unfairness in the equity investor getting, to paraphrase Ms. McShane, "zero profit" on the debt.

340. CAPP argued that the Utilities provide no legal authority that would suggest that the legislated scheme of rate-of-return/rate base regulation fails to set a reasonable price for service. Moreover, such an argument would go to the roots of the legislation and could not be confined to one issue like management fees.

341. CAPP submitted that what the utility gets for managing the assets, over and above the rate of return on rate base, is the recovery of all proper costs of operating the system. CAPP cited *Northwestern 1961* in support of the concept that the return on the capital invested by the investor is "net":

> In approving rates which will yield a fair return to the utility upon its rate base, it is, of course, essential for the Board to estimate the expenses which will necessarily be incurred thereafter in rendering the service. The fair return permitted is, after deducting from the gross revenue these necessary estimated expenditures and such necessary outgoings as taxes, including income taxes. The Board can only come to a conclusion as to what rates should be approved by determining as closely as may be done in advance the probable amount of these expenditures.[221]

342. Citing *Stores Block*, CAPP submitted that the entire discussion in that decision is premised on investment by private investors, not by customers, as is clear from the following passage:

> The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will

[221] *Northwestern 1961* at page 405.

necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.[222]

343. CAPP argued that, if the customers, in addition to contributing free capital to obtain service (and so lower rates than would otherwise have been the case if the utility had made the investment), were to be required to pay the equity investor a return to manage that customer's capital contribution then it calls into question the rationale of *Stores Block*.

344. CAPP submitted that it is only in those rare few cases of the vanished rate base that the management fee comes into play since, otherwise, the equity investor would receive no return. In such cases the management fee is a substitute for the return on equity capital. It may also be observed that, when the utilities cite such rare cases of vanished rate base as precedent, they completely contradict their argument that the management fee issue is separate and distinct from the fair return.

345. With respect to the Utilities' argument regarding *quantum meruit*, CAPP submitted that *quantum meruit* applies in common law to the provision of goods or services that have been provided in the expectation of payment and where there is no contract that applies to the price for those goods or service. In this case, CAPP argued, here is a contract for the provision of services by the utility to the customer and it is governed by the tariff approved by the regulator. The approved tariff specifies the price to be paid and the terms and conditions including when the utility is not obliged to finance an investment in plant and the customer must finance the investment with the customer's own capital.

346. CAPP submitted that the provision of customer contributions is a creation of the regulatory model: it is not something that stands outside the regulatory model that is governed by common law principles and there is no gap to be filled by common law principles. CAPP argued that judicial observations, in obiter dicta, to the effect that regulatory statutes are consistent with *quantum meruit*, a concept that applied to common carriers at common law, do not assist the Utilities' argument.

347. In reply argument, the Utilities noted that there was no disagreement that the Commission is charged with ensuring that, in setting rates, it provides the utility a reasonable opportunity to recover its prudently incurred costs, including a fair return on investor-supplied capital.[223] The Utilities asserted that an economic cost or opportunity cost, which reflects normal profit for the service rendered, is therefore recognized as legitimate for cost recovery: the Utilities noted return on equity as an example, citing *TransCanada Pipelines Limited v. Canada (National Energy Board)*, 2004, FCA 149, at paragraphs 6-12 and 32-34 as authority that such costs are recoverable in rates. The Utilities asserted that the management fee, like return on equity, is an economic cost as opposed to an incurred cost.[224]

348. The Utilities distinguished CAPP's discussion of the *Stores Block*[225] decision, stating that that decision dealt with a different matter (i.e., asset disposition not CIAC) and argued that it did not displace the utility's right in law to receive fair compensation commensurate with the value of services rendered.

222 *Stores Block* at paragraph 70.
223 Exhibit 220.02, Utilities reply argument, paragraph 115.
224 Exhibit 220.02, Utilities reply argument , paragraph 117.
225 *ATCO Gas &Pipelines Ltd. v. Alberta (Energy &Utilities Board)*, [2006]1 S.C.R. 140 (*Stores Block*).

6.2.3 Should the utilities receive a fee for management of contributed assets? If so, should a management fee be awarded in addition to the allowed rate of return or can the ROE be adjusted to include compensation for the management of CIAC? Alternatively, can the ROE remain constant and a management fee be awarded through adjustments to the debt/equity ratio of individual utilities?

349. The Utilities argued that CIAC funded assets are fully integrated into other regulated assets that the Utilities own and operate and that the services that the Utilities provide to the customers that make contributions are the same as for all other customers. The Utilities stated that the only difference is that the Utilities do not finance CIAC assets and do not receive any compensation, or margin, either for providing valuable services related to, or for bearing risks associated with, constructing, owning, operating, and managing those assets.[226] The Utilities submitted that they should earn a margin or fair compensation for all of the service they render using all of the assets employed in rendering such service.

350. In argument, the Utilities noted Ms. McShane's evidence that in a "real world" competitive market, a business would expect to be compensated for the totality of the resources that it deploys, including physical capital and labour and enterprise capital. Further, in competitive markets, in economic terms, firms expect to earn a normal rate of profit; where a normal rate of profit recognizes the opportunity costs of all the resources devoted to the business. Finally, the Utilities noted that there are numerous competitive industries that have very little invested debt and equity, because they are primarily service industries (a number of which were identified in response to UCA-Utilities-48). Firms in these industries would all expect to generate a profit from the services that they provide irrespective of the fact that there is little invested capital. And, like the Alberta Utilities, these firms would expect to generate a profit on the totality of their business, not just some of their business operations.[227]

351. The Utilities stated that the size of CIAC is a problem unique to Alberta and noted that, in aggregate, total unamortized CIAC of the Alberta Utilities in 2007 was approximately $1.3 billion out of a total rate base net of contributions of approximately $6.6 billion and that, based on 2010 estimated data, CIAC accounts for approximately 16 per cent of gross rate base. The Utilities stated that there is a significant disparity between the percentage of CIAC of the Alberta Utilities and that of their Canadian peers and noted that, for a typical regulated Canadian utility, the CIAC to total rate base percentage is less than four per cent.[228] In Table 1 of her evidence, Ms. McShane provided the following list of regulated Canadian utilities and their contributions as a per cent of gross rate base:

226 Exhibit 209.01, Utilities argument, paragraphs 181 and 182.
227 Exhibit 209.01, Utilities argument, paragraphs 184 to 186.
228 Exhibit 209.01, Utilities argument, paragraphs 187 and 188.

Table 11. Proportion of contributions to gross rate base for ex-Alberta utilities

Utility	Contributions as a Per cent of Gross Rate Base
Foothills Pipelines	0.6%
FortisBC	8.8%
Gaz Metro	3.9%
Maritime Electric	4.5%
Newfoundland Power	2.8%
PNG-West	3.8%
Terasen Gas	6.3%
TransCanada Pipelines	0.5%
Westcoast Energy	0.5%
Median	**3.8%**

352. The Utilities submitted that limiting the application of the two per cent margin to CIAC balances in excess of four per cent of gross (inclusive of contributions) rate base would appropriately recognize the fact that other utilities in Canada, that could be considered comparable to the Alberta Utilities, also have some CIAC, albeit in generally smaller proportions.[229] The Utilities noted that some level of contributions may be needed to help maintain fairness amongst customers but the current regime neglects to address the fairness issue as between customers and the Utilities. The Utilities refuted Mr. Marcus' assertion that the requested management fee would "negate" the purpose of contributions stating that receiving compensation where compensation is merited does not negate the purpose of contributions, since customers are not paying what they would pay if the CIAC-financed assets had instead been fully funded by investor supplied capital. The Utilities noted that a utility would not choose to construct, own, operate and manage assets on which it receives no profit margin but it has no choice since it is mandated to do so.

353. The Utilities stated that the management fee was recommended independently of the generic ROE and the capital structures appropriate for each utility, that it was a separate compensation from the fair return on rate base and that it would compensate the Utilities for something not compensated for under the existing cost of service regulatory scheme. The Utilities stated that the two concepts, fair return on rate base and the management fee, are complementary, with the management fee augmenting the traditional rate base/rate of return model to ensure fair compensation to the Utilities.[230] The Utilities noted that, during the oral proceeding, Ms. McShane confirmed that the need for a management fee arises because the traditional rate base/rate of return model does not fit the unique circumstances of the Alberta Utilities and does not afford adequate, or any, compensation for opportunity cost or value of service. The Utilities noted that, in addition to the value of services rendered, there are business risks and liabilities, other than the operating leverage risk, that the utilities are exposed to and for which the Utilities should be separately compensated in the management fee.

229 Exhibit 209.01, Utilities argument, paragraph 189.
230 Exhibit 209.01, Utilities argument, paragraph 194.

354. The Utilities took exception to Mr. Marcus' suggestion that, if the Commission is compensating for anything other than risk, then only a minimal amount should be awarded. The Utilities stated that the position advanced by Mr. Marcus downplays the risks taken and the value of services provided and the point that Mr. Marcus ignores is that the functions performed by the Utilities in relation to CIAC extend beyond operating and maintaining assets and included, for example, building transmission substations on, in effect, a turnkey basis for no compensation. Since constructing assets comprises a significant portion of activities associated with CIAC, the Utilities stated that this was further evidence that Mr. Marcus is undervaluing the services provided by the Utilities and that his "percentage adder on O&M" approach does not provide a reasonable estimate of that value.

355. The Utilities noted that IPCAA opposed the management fee on the basis that:

> IPCAA also believes the TFO's management fee proposal has an element of double charging. This potential for double charging is a matter of particular concern in the case of the customer who has already made a customer contribution since the additional management fee for the same assets adds no value.[231]

356. The Utilities submitted that IPCAA's reasoning is flawed and that there is no double charging since the Utilities do not recover the cost of capital provided by customers. Rather, the Utilities would now recover a fee for the valuable construction, operation and maintenance activities associated with continuing utility service.[232]

357. The Utilities noted that the Commission has previously acted to ensure that entities it regulates receive fair and reasonable compensation for the functions they perform and services they render in circumstances where the traditional cost of service methodology did not render appropriate results. The Utilities made reference to the retail energy providers who have little invested capital and are compensated by way of a return margin. In addition, the Utilities made reference to other jurisdictions in Canada and the U.S. where regulators have augmented the rate base/rate of return model in order to provide fair compensation to the utility. The Utilities noted that, while the circumstances of the Alberta utilities are not identical to those cited, the examples from these other jurisdictions provide a useful precedent for the regulatory approach the Utilities are proposing.[233]

358. The Utilities noted that Mr. Marcus acknowledged that, when the proportion of CIAC to total rate base becomes sufficiently large, the rate base/rate of return model may need to be replaced with an alternative.[234] The Utilities then stated that, as Mr. Marcus appears to agree with the concept of providing compensation or a margin for services rendered and risks assumed, the only disagreement appeared to be a question of how much CIAC is required to trigger payment of a service fee.[235]

359. In responding to the submission by various parties that contributions are already taken into account when setting the capital structure and return on equity, the Utilities stated that recovery of a utility's cost of capital does not address compensation for services provided

231 Exhibit 82.02, IPCAA Rider I evidence, pages 5 and 6.
232 Exhibit 209.01, Utilities argument, paragraphs 199 and 200.
233 Exhibit 209.01, Utilities argument, paragraph 202.
234 Exhibit 209.01, Utilities argument, paragraph 202.
235 Exhibit 209.01, Utilities argument, paragraph 203.

utilizing customer supplied capital. The Utilities stated that the recommended capital structure and ROE for the Alberta Utilities have been made independently of the issues related to CIAC. The Utilities submitted that there is no evidence the Commission or its predecessors have, either explicitly or implicitly, reflected the value of services provided with respect to, or risks related to, CIAC in setting the capital structures or ROE's in prior cost of capital decisions for Alberta Utilities.[236] They noted that the CIAC issue did arise with respect to AltaGas Utilities in the 2004 GCOC proceeding but stated that there was no reference to CIAC in the determination of relative business risk. Finally, the Utilities noted that the Commission determined that the management fee issue, when raised in other proceedings, should be considered on a more comprehensive industry wide basis in a subsequent proceeding. The Utilities stated that this was clear recognition from the Commission that the issue had not been previously determined.[237]

360. The Utilities addressed the fact that Interveners raised the timing of the management fee proposal and stated that no adverse inference can be drawn for the fact that the Utilities did not address the CIAC issue in prior cost of capital recommendations and that this simply reflected that, until recently, the Utilities attempted to deal with the CIAC issue through proposed changes to investment policy rather than seeking higher returns or thicker equity ratios.[238]

361. The Utilities stated that their position is that the management fee should be implemented as a separate revenue requirement item distinct from ROE and capital structure. The Utilities proposal maintains the traditional rate base/rate of return construct as regards investor supplied capital and, as such, the ROE must remain the same for each of the Utilities.

362. The Utilities also stated that implementing the management fee as a separate revenue requirement item would appropriately reflect the fact that the two concepts compensate for something different. The fair return relates to assets that are financed by the utility whereas the management fee relates to assets that are constructed, owned and operated by the utility but are financed by customers. As there is no overlap and the compensation for each is arrived at independently, there is no basis for accounting for the management fee through an adjustment to ROE. Accounting for it through ROE also loses the scalability feature of the management fee proposal which would award each utility a fee calculated only on the proportion of CIAC each utility has at any particular point in time.[239] Further, the Utilities submitted that there is no valid basis for reducing the allowed return on account of a management fee.[240] They also stated that while ROE and capital structures are assessed against "comparable" companies, those firms do not have the high levels of CIAC experienced by the Alberta Utilities, therefore, the fair return does not account for the CIAC assets.[241] Finally, treating the management fee as an offset would understate the fair return determined by the Commission applicable to investor supplied capital.[242]

236 Exhibit 209.01, Utilities argument, paragraphs 205 and 205.
237 Exhibit 209.01, Utilities argument, paragraph 210.
238 Exhibit 209.01, Utilities argument, paragraph 206.
239 Exhibit 209.01, Utilities argument, paragraphs 211 to 213.
240 Exhibit 209.01, Utilities argument, paragraph 214.
241 Exhibit 209.01, Utilities argument, paragraph 215.
242 Exhibit 209.01, Utilities argument, paragraph 216.

363. The Utilities noted that in evidence they had stated that the adoption of a management fee would have a *de minimus* impact on credit metrics and financial risk and added that any improvement would be insufficient to warrant offset to ROE or capital structure.[243]

364. The Utilities stated that the suggestion that CIAC be awarded through an annual adjustment to the debt/equity ratio of individual utilities was not a reasonable alternative and submitted that the deemed common equity ratio should remain constant as it is intended to be a relatively permanent proportion of the investor supplied capital to be changed only when the circumstances of the utility change materially.[244]

365. Finally with respect to changes to investment policies or Rider I, the Utilities submitted that these changes, if they occur, might result in the amount of the management fee declining over time but would not change the fact that there are significant contributions now over which services are being provided for no compensation.[245] The Utilities added that policy amendment, although necessary to restrict growth in contributions, is not a solution by itself and that as long as there remain substantial contributions outstanding there remains a need for a management fee.[246] The Utilities also stated that the proposed Rider I might offer some mitigation to TFOs but would not address the contributions that are made to the distribution utilities or gas utilities.[247]

366. The UCA argued that, under cost-based regulation, utilities are entitled to recover their costs of providing service through rates, and if the Utilities could show that CIAC gives rise to utility or shareholder costs or risks as recognized by the legislation, it may be appropriate to allow them to recover those costs through a management fee or other mechanism. However, the UCA argued, the Utilities have not shown that there are costs associated with holding CIAC balances, and they have not provided any other reasonable basis on which to impose such a fee.[248]

367. The UCA submitted that Ms. McShane had advanced three basic arguments in support of a management fee in her evidence, which it summarized as follows:[249]

a) CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders.

b) CIAC creates financial leverage that results in increased financial risk and an increase in the cost of equity for shareholders.

c) A management fee is appropriate as a matter of fairness in order to properly reflect the expectations of utilities and the value of the services that they provide.

Operating leverage

368. The UCA submitted that, in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has

243 Exhibit 209.01, Utilities argument, paragraph 217.
244 Exhibit 209.01, Utilities argument, paragraph 219.
245 Exhibit 209.01, Utilities argument, paragraph 229.
246 Exhibit 209.01, Utilities argument, paragraph 226.
247 Exhibit 209.01, Utilities argument, paragraph 179.
248 Exhibit 210.02, UCA argument, paragraph 240.
249 Exhibit 210.02, UCA argument, paragraph 242.

some theoretical validity since CIAC can create incremental operational risk. However, the UCA submitted that in practice the numbers are very small, and in the actual circumstances of the Utilities the risk is *de minimus,* so any fee imposed to compensate for it would be trivial. Moreover, the UCA submitted that the Utilities already differ in the amount of operating leverage and risk that they bear without those differences ever having been recognized for rate making purposes, and there is no reason to recognize only risks associated with CIAC balances.[250]

369. The UCA submitted that the effect of CIAC is to magnify the effects of changes in operating costs, whether positive or negative, on the effective return. On an expected or probability-weighted basis, there is no impact on average shareholder returns, but in principle the variability of those earnings increases with CIAC. In principle, that increased earnings variability should increase the cost of equity slightly for the utility with assets financed with more CIAC. However, the UCA submitted that whether the reference point for the maximum shift caused by operating leverage is four or 40 basis points, it is still an extremely small effect. In response to examination by Commission Counsel, Mr. Marcus pointed out that the risk that is imposed by contributions is so small that it falls within the rounding error and the financial flexibility adjustments of all the witnesses who provided evidence in the proceeding.[251]

370. The UCA argued that the size of operating leverage effect illustrated in Table 2 of Ms. McShane's management fee evidence is a function of (a) the variability in operating costs, and (b) the size of the rate base on which a regulated return is earned. It has nothing to do with CIAC uniquely, but rather with the relationship between the variability of operating costs and the size of the rate base. The UCA submitted that, for all utilities, the size of the rate base is a function of numerous factors, only one of which may be CIAC. The UCA argued that the most obvious example of a non-CIAC determinant of rate base is accumulated depreciation.

371. Referencing Ms. McShane's Table 2, the UCA stated, if the label CIAC at the fourth line was instead relabelled "Accumulated Depreciation," then the first utility, being new, would have a rate base equal to gross plant, but the second utility, being several years older , would have recovered 20 per cent of its initial investment through depreciation charges. In that situation, all of the numbers shown in the table, and all of the effects of what is now labelled Accumulated Depreciation on the variability of earnings, are exactly that same as they were in the case where the second line was labelled CIAC. The UCA argued that it would not be reasonable to give the shareholders of the second utility a management fee just because they have recovered 20 per cent of their investment through depreciation charges, even though their position is no different from that of the shareholders of the second utility in Ms. McShane's table who recovered 20 per cent of the cost of the firm's facilities from contributing customers.[252]

372. The UCA submitted that, while in normal situations these types of differences in operating leverage exist all the time for different reasons, there are situations where operating leverage and the associated risk can become extreme, and where a management fee or equivalent mechanism may be reasonable. A clear example of that, the UCA submitted, is the High Island Offshore System (HIOS) case dealt with at the FERC. In that case, the HIOS regulated pipeline had had its rate base depreciated down to essentially nothing. In that situation, HIOS

[250] Exhibit 210.02, UCA argument, paragraph 243.
[251] Exhibit 210.02, UCA argument, paragraphs 249 and 250.
[252] Exhibit 210.02, UCA argument, paragraphs 252 and 253.

shareholders have no money invested in the business, and earn no return or profit, but are still exposed to risk related to variability in operating costs and revenues.

373. The FERC confirmed in the specific circumstances unique to the HIOS case that its policy is to allow the pipeline to earn a management fee roughly equal to the standard rate of return applied to a deemed rate base equal to about five per cent of the pipeline's original investment or gross plant. The UCA submitted that is a management fee that is very small, and moreover only available when the utility has reached a point where its shareholders are earning essentially a zero return. The UCA argued that this is an extreme and unique situation that is completely unlike the situation facing any of the Alberta Utilities.[253]

374. The UCA stated that the FERC made itself very clear in the HIOS case that the decision does not stand for the principle supported by the Utilities here that utilities should get *both* a rate of return and a management fee, contrary to the implication of Ms. McShane's testimony.[254] In rebuttal evidence, the UCA stated:

> 165 The FERC decisions have nothing to do with returns on pieces of a company (i.e., the Utilities claim that contributed plant should be treated as separate from plant funded by investors). The FERC decisions provide a methodology that applies only when the rate base paradigm does not provide an adequate return for the operational risk because rate base is zero or extremely low for a given company or plant. This point is made extremely clear in the HIOS Order on Rehearing, where FERC stated:
>
>> On the other hand, however, a large investment in a new HIOS project, similar to the $80 million invested in the non-jurisdictional East Breaks Gathering System, would *terminate the management fee* in favor of a return to the traditional return on rate base methodology.[255] [emphasis added] [footnotes omitted]

375. Another factor to be considered, the UCA submitted, is that these types of risks or costs must have existed for years or decades, because the average CIAC levels have been consistent over a long period. Before the management fee issue was raised relatively recently in the ATCO Electric and AltaLink proceedings, none of the Utilities had identified any risk or cost associated with CIAC or complained that they were not being appropriately compensated for those risks and costs, the UCA argued. Whatever effects CIAC has on utility cost of equity must have been already accounted for by the Commission.[256]

376. The UCA submitted in its rebuttal evidence that Ms. McShane has made an implicit assumption that the Commission and its predecessors never thought about risks created by CIAC and therefore must grant an increase equal to the full amount of her recommendation. The UCA submitted that, if in fact the regulators granted a return commensurate with the utility's business risks in past cases, then granting an increase in this case due to risk associated with the full amount of contributions will compensate the utilities twice for the same risk.[257]

377. Further, the UCA stated that it is unreasonable to assume that the alleged risks of contributions were never considered by the Alberta regulator, unless one also reaches the

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253 Exhibit 210.02, UCA argument, paragraphs 255-257.
254 Exhibit 210.02, UCA argument, paragraph 258.
255 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 165.
256 Exhibit 210.02, UCA argument, paragraph 265.
257 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 168.

conclusion that utility rate of return witnesses in past cases over the last two decades – including Ms. McShane - did not conduct adequately thorough and complete risk assessments for their clients. The UCA argued that it appears that utility witnesses made almost no references to risks arising from contributions in past rate cases, even when certain Alberta utilities had as much as 35 per cent of their distribution property as CIAC in the 1990s and early 2000s.[258]

Financial risk

378. With respect to the second argument (financial risk), the UCA stated that CIAC does not create any financial risk for shareholders and imposes no costs on them. Financial risk is therefore not a justification for imposing a management fee. Any financial risks or related shareholder costs associated with CIAC balances must have existed at essentially the existing or higher levels for many years, without the Utilities or the Commission ever pointing them out or recognizing them in rates.[259]

379. The UCA described the second argument as claiming that, because CIAC reduces the proportion of equity on which a return is earned relative to the total asset base, it leads to a lower equity ratio. Ms. McShane then analogized that reduction in equity as a proportion of the total asset base to the situation where a utility's financing of rate base includes debt, and the accepted principle that, when the debt ratio increases that increases financial risk, which in turn increases the cost of equity. The UCA submitted that Ms. McShane then characterized CIAC as debt-like and relied on the analogy with debt as the basis for her calculation of a proposed management fee. That calculation involves an after tax weighted average cost of capital (ATWACC) analysis in which she calculates a leverage adjustment that is supposed to reflect the increase in the cost of equity as the level of CIAC, and in her view the leverage or debt-like ratio increases, based on the premise that the ATWACC is constant.[260]

380. The UCA submitted that the difficulty with that argument is that CIAC does not resemble debt in any sense that is relevant to the concept of financial risk or the calculation of a leverage adjustment. The UCA further submitted that, with CIAC, there is no contractual interest obligation, and not even a principal repayment obligation. CIAC therefore creates no volatility in earnings and no financial risk, as that term is normally understood and explained in Appendix D to Ms. McShane's management fee evidence. It therefore does not increase the cost of equity for the firm, or impose any cost on shareholders.[261]

381. The UCA argued that, in her evidence, Ms. McShane provided no explanation of how CIAC increases the volatility of equity returns by creating financial risk, and that she provided no table or illustration analogous to her Table 2 to explain and demonstrate how CIAC creates financial risk that is distinct from the operational risk that Table 2 illustrates, for example using a hypothetical case where operating costs are constant.[262]

382. The UCA argued that the financial risk appears to be a risk that the Utilities have never noticed, even though they claim that they require an additional 40-100 basis points of equity return to compensate them for it, and that the lower equity ratio that Ms. McShane points to will arise, for example, through the accumulation of depreciation. Further, the UCA submitted that, if

258 Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 169.
259 Exhibit 210.02, UCA argument, paragraph 244.
260 Exhibit 210.02, UCA argument, paragraphs 271 and 272.
261 Exhibit 210.02, UCA argument, paragraphs 273 and 276.
262 Exhibit 210.02, UCA argument, paragraph 277.

the financial risk argument falls, the entire logical underpinning of Ms. McShane's calculation of her proposed management fee must fall as well, since it is premised entirely on that argument.[263]

Value of service

383. Lastly, the UCA argued that Ms. McShane's third argument is inconsistent with the legislation providing for cost-based ratemaking, the standard regulatory paradigm, and the fair return standard.[264]

384. The UCA stated that Ms. McShane's last argument is that it is not fair for the Utilities to be required to operate CIAC-financed facilities without earning a profit in connection with that activity, and that no rational competitive enterprise would operate expecting to recover only their expenses and earn a return on only a portion of the assets they use to provide services.[265]

385. As Mr. Marcus explained, the UCA argued, the argument that utilities are being deprived of a return is inconsistent with cost-based rate-making and the economic principles that underlie it. The entire theory on which the return on equity is set by regulatory agencies is that the required return on equity capital equals the (opportunity) cost of equity capital. As stated in Mr. Marcus' evidence:

> If the ROE equals the cost of equity, then it follows from elementary logic that investors should not care whether the utility invests the equity here, whether it invests the equity in a different project, or whether it passes money back to investors through dividends or share buybacks (or does not raise equity capital in the market) so the investors can invest capital elsewhere at a similar rate of return.[266] [footnotes omitted]

386. The UCA submitted that the evidence of Mr. Marcus explained why paying utilities a rate of return on capital that is never invested in the first place (through a management fee) provides skewed compensation for the utility. Mr Marcus stated in his evidence:

> Q. Please explain with reference to practical considerations why shareholders would be better off if they got an equity return on contributed property than if there were no contribution at all and shareholders simply invested equity in additional amounts of utility property?
>
> A. Giving the shareholders a rate of return when they do not have to make an investment is simply NOT equivalent to giving them a rate of return on an investment that they actually make.
>
> The Utilities' arguments focus on the asset side of the balance sheet (the contributed assets), but fail to recognize the liability side of the same balance sheet (that with contributed assets, they also require less debt and less shareholder equity).
>
> If the shareholders are paid a return as if they had invested equity in CIAC projects, but do not actually invest anything, they still have the money available for other valuable uses. Consider a project that a utility would have invested in, except it was required to collect CIAC instead. Two things happen:

263 Exhibit 210.02, UCA argument, paragraphs 279 and 281.
264 Exhibit 210.02, UCA argument, paragraph 245.
265 Exhibit 210.02, UCA argument, paragraph 282.
266 Exhibit 210.02, UCA argument, paragraph 285.

> 1. The utility does not receive a stream of earnings on the capital it would have invested in the new project. This is the sole focus of the Utilities' theory that equity investments are foregone when they invest in contributed property.
>
> 2. Because the utility has not invested its equity capital in projects paid for with CIAC, its equity capital is different than if it had invested in those resources in one or two ways:
>
>   a) If the utility would otherwise not have enough equity to invest in new resources treated as CIAC, it would have had to raise that equity in the capital markets. In this case, it avoids having to raise equity in the capital markets.
>   b) If the equity was available to it in the first place but not needed because of CIAC, the utility still has the equity available. The equity capital that is freed up because the investment was paid for using CIAC has a large number of other long-term uses ranging from buying back stock, paying more dividends, or making more investments (either regulated or unregulated).
>   c) The utility could invest in the longer term in additional projects (e.g., capital maintenance) if it had more equity available. In such a case, the equity not invested in contributions may simply be invested in different projects, not "lost" even under the Utilities' theory.
>
> To make decisions that consider the first factor (the asset side of the balance sheet) but do not consider differences in the availability of equity capital due to the CIAC (the liabilities and equity side of the same balance sheet) violates the principles of elementary finance, economics, and accounting and is, thus, extremely poor public policy. A decision to pay a full return on equity that is never invested in the first place, while still allowing the utility to invest the equity and earn a return (or alternatively never have to raise the capital at all) would give the shareholders far more money than if the utility had no contribution policy and simply invested the full amount in every project that was requested, regardless of cost. Therefore, paying shareholders an equity return without an equity investment clearly cannot be viewed as fair compensation, but is, instead, extremely skewed.[267]

387. With respect to the Utilities' fairness argument, the UCA submitted that Ms. McShane effectively acknowledged that her proposal is not consistent with the standard model of utility regulation, but said that it reflects a defect in the standard model, because the standard model does not fully reflect value in the way that competitive markets do.[268]

388. The UCA argued that this suggestion, in effect, is that there is something unfair or economically inappropriate with the concept of cost-based rate-making. The UCA cited Mr. Marcus' explanation that conventional utility regulation sets prices for utility service at a level that, in principle, allows the utility to recover exactly its costs, including the cost of equity capital or a fair return for shareholders. The UCA argued that there is nothing unfair or economically inappropriate about the model (cost-based rate-making) and that it is completely consistent with well-known economic principles.[269]

267 Exhibit 81.04, prepared testimony of William B. Marcus, pages 48 and 49.
268 Exhibit 210.02, UCA argument, paragraph 289.
269 Exhibit 210.02, UCA argument, paragraph 290, 291, and 294.

389. In reply argument, the UCA noted that the Utilities had simplified the management fee issue by abandoning the first two arguments (operating leverage/risk and financial leverage/risk) and relying entirely on the fairness or value of service argument. The UCA further stated that the Utilities made it clear that the proposed management fee is separate from, and in addition to, any compensation due to shareholders in respect of amounts invested or risks borne by shareholders and that in the context of arguing that the management fee should not be treated as an offset to allowed ROE, the Utilities emphasized that it is intended to compensate the utility for something different from, and in addition to, the cost of equity capital.[270]

390. The UCA argued that the Utilities' position is that the management fee has nothing to do with ensuring that shareholders earn a fair return, or that shareholders are adequately compensated for the risks that they face, because all of that is already accomplished through the Commission's ROE and capital structure determinations. It therefore apparently has nothing to do with compensating shareholders for any incremental CIAC-related operating risks of the kind acknowledged by Mr. Marcus, or with any "phantom financial risk" that CIAC imposes on shareholders.[271]

391. The UCA further submitted that, in order to approve the management fee proposal, the Commission must repudiate not simply a regulatory "policy," but the entire economic and logical basis for the cost-based rate-making approach that it has applied for decades.

392. The UCA stated that one of the arguments advanced by the Utilities is that no rational business would enter into or operate facilities if it did not expect to earn a profit on that activity. The Utilities referred to a variant of that argument, where they discussed Mr. Marcus's evidence in relation to the discounting of services as analogous to operating facilities at no profit. While that exchange involved a side issue, the point was that the analogy with the supposed behaviour of competitive businesses is not correct because the issue is whether a firm earns an appropriate profit on its entire business, not on individual parts of the business. Mr. Marcus gave the example of brushing activity by utilities, where the utilities do not expect to "earn a profit" on brushing, but it is something they have to do in order to earn a fair return on their investment in the overall business. If the shareholders earn a fair return on their investment, which they will do under the cost-based rate-making model in the absence of a management fee, then regardless of how that investment is deployed they have no complaint and there is no unfairness.[272]

393. In response to the question of whether the Utilities should receive a fee for management of contributed assets, the CCA submitted that both operations and maintenance expense amounts awarded and the current Commission approved methodology for the determination of rate of return adequately compensates for the management of Utilities' operational assets, including those financed by customers through CIAC.

394. In reply argument, the CCA submitted that it disagreed with the Utilities' argument that customers are providing zero compensation for CIAC assets. The CCA considered that customers are responsible for 100 per cent of the ownership costs of the CIAC assets and customers are paying for the management of the assets in the form of revenue requirement items. These items include any management, including board of director fees and expenses, insurance, and engineering expenses. The CCA stated that the value of services provided by the utility in

270 Exhibit 221.02, UCA reply argument, paragraphs 86, 90, and 91.
271 Exhibit 221.02, UCA reply argument, paragraph 92.
272 Exhibit 221.02, UCA reply argument, paragraph 104.

the management of CIAC assets are currently paid for by customers, and that by paying for assets up front in the form of CIAC customers are eliminating the risk to the utility holding the assets.[273]

395. The CCA also argued that the Utilities are compensated for invested capital, thus if there is no invested capital there should be no return. By having customers prepaying ownership costs in the form of CIAC, utilities should not be allowed to earn an excessive return. In particular, the CCA argued that a two per cent return is excessive, given the current interest rate and inflation rate environment. The two per cent equates to in excess of 50 per cent of current 30-year Government of Canada bond yields. The CCA argued that the Utilities are requesting 50 per cent of the risk free return and payment of all related operation and maintenance expenses, including management, engineering, insurance and board of director fees, for an asset they require customers to pay for up front.

396. The CCA submitted that a management fee should not be ruled on until Rider I effects are understood and could be forecast. The CCA argued that the Rider I will eliminate the need for a management fee, as CIAC levels will be reduced dramatically. The CCA also stated that it did not consider that a management fee should be implemented at the distribution level, noting that distribution utilities' CIAC levels are not comparable with transmission levels.

397. In responding to the question of whether the Utilities should be awarded a fee for management of contributed assets, IPCAA argued that there is no basis for a management fee of the nature applied for by the Utilities. Moreover, IPCAA submitted that adjustments to the ROE or the debt/equity ratio could only be justified if the management of property paid for by customers in some way increased utility risk, which, IPCAA argued, it does not.[274]

398. IPCAA reiterated the position set out in its evidence that with the AESO's proposed Rider I, there is no basis for a management fee, but stressed the fact that the Rider I proposal is not tied to the management fee proposal.

399. IPCAA noted that another concern with the proposed management fee is the potential double charging for DFO customers. If the TFOs are allowed to earn a management fee on TFO assets paid for by a customer contribution, IPCAA argued, then the DFO customers will be paying twice. First, they will pay a fee to the TFO for asset contributions from the DFO (that the DFO will pass through to its customers). Second, they will pay a return to the DFO for the AESO customer contribution in the DFO rate base for the TFO asset.[275]

400. CAPP argued that the management fee as proposed by Ms. McShane is unjustified and also excessive, and that CIAC should be treated as a deduction from rate base prior to calculating return and there should be no additional fee for management.[276]

401. In commenting on the justification for the award of a management fee, CAPP submitted that where the rate base is disappearing – the 'vanishing rate base' conundrum – there is an issue, as Mr. Marcus discussed, of providing the incentive to the company to continue to provide service and operate the system. Such situations are very rare and, CAPP submitted, the Utilities

273 Exhibit 218.01, CCA reply argument, paragraphs 22, 23, and 24.
274 Exhibit 212.01, IPCAA argument, paragraphs 23 and 24.
275 Exhibit 212.01, IPCAA argument, paragraph 29.
276 Exhibit 207.02, CAPP argument, paragraph 98.

requesting a management fee are instead in growth mode. CAPP argued that if utility investors had been harmed in taking CIAC all these years, the practice would never have developed and certainly would not have continued. CAPP submitted that, according to Ms. McShane, the Utilities have been undercompensated with returns that have been far too low on account of no allowance being made for the so-called "cost" to the utility investor from managing the assets bought with free money. If this were true, CAPP argued, one would expect to have seen some evidence of this in the marketplace. The Utilities should be selling at a discount because of this: yet they are not.[277]

402. The Utilities responded in reply argument to a number of the issues raised by interveners in response to the question of whether the Utilities should receive a management fee for contributed assets.

403. In response to the assertion that the Utilities are being fully compensated for the management of CIAC financed asset, the Utilities submitted that merely covering out of pocket costs is not compensation for the provision of value-added services.[278]

404. Noting that the principal basis for proposing the management fee was fairness, the Utilities submitted that while contributing factors such as increased operational risk and financial risk may appear minor in comparison, they are nevertheless valid. The Utilities noted that the UCA admitted the theoretically validity of the incremental operational risk and that attempts to trivialize those risks flatly ignore the $1.3-$2.5 billion of existing and forecast assets that the Utilities are now required to construct and operate on a wholly non-profit basis.[279]

405. The Utilities argued that the atypically high levels of CIAC in Alberta were not disputed by interveners. In response to intervener claims that the Utilities did not historically seem concerned about the size of CIAC or have not noticed the risk related to CIAC until recently, the Utilities stated that the issue was addressed in 2009 (ATCO Electric and AltaLink's GTA's) and that the electric distribution utilities have made concerted efforts to see changes made to investment policies.[280]

406. The Utilities stated that the UCA's purported analogies between CIAC and accumulated depreciation and vanishing rate base were misguided, and the Utilities also took exception to the fact that these positions were not advanced in evidence and could not be tested. Accordingly, the Utilities submitted that these positions should be accorded no weight by the Commission. In addressing these positions put forward by the UCA, the Utilities stated that the UCA's analogy between accumulated depreciation and CIAC is inapposite since no fee is sought to be recovered in respect of accumulated depreciation or amortized CIAC balances.

407. The vanishing rate base analogy, the Utilities submitted, fails to recognize that the FERC acknowledged that, in principle, compensation was due for valuable service rendered even where no investor-supplied capital was involved. While the FERC noted that the fee was wholly in lieu of a return on investor-supplied capital and not in addition to it, the Utilities submitted that it does not address the issue of CIAC, as the UCA acknowledged in Section 4.4 of their argument, wherein the UCA stated that it was not aware of any other jurisdiction that has approved a fee or

277 Exhibit 207.02, CAPP argument, paragraphs 107 and 111.
278 Exhibit 220.02, Utilities reply argument, paragraph 132.
279 Exhibit 220.02, Utilities reply argument, paragraph 133.
280 Exhibit 220.02, Utilities reply argument, paragraph 134.

other mechanism to compensate shareholders for the management of contributed assets.[281] The Utilities stated that where no rate base exists, the FERC approach may be appropriate and that, in this case, a substantial rate base composed of both investor and customer supplied capital does exist for which compensation is appropriate, though calculated differently for return on investor capital.[282]

408. The Utilities stated that the FERC cases, the RRO, water utilities and PPAs on depreciated power plants noted in the UCA's argument all support a management fee since they acknowledge that zero compensation for the value of services rendered does not result in just and reasonable rates.[283]

409. Noting that the UCA took issue with the analogy drawn between CIAC and debt, the Utilities argued that the accounting theory advanced by the UCA in its discussion appears to be new and untested evidence and should therefore be rejected by the Commission. Referring to specific sections of the UCA's argument, the Utilities argued that contrary to what the UCA stated in paragraph 275, interest is not the only thing which creates financial risk for shareholders; it ignores the principal repayment obligation. Further, contrary to paragraph 286, the Utilities are not solely focused on the asset side of the balance sheet. If there is an asset on the asset side, there must be something on the liability side. Since it is not equity, it must be a liability.

410. The Utilities stated that as a matter of principle, under IFRS, CIAC is accounted for as deferred revenue and therefore recorded as a liability on the balance sheet. The IFRS accounting entries are not driven by whether the regulator views the CIAC as debt or not. More importantly, debt rating agencies and other capital market participants do their analysis and form their opinions based on financial information prepared under IFRS. Title to the assets rests with the utilities and, under IFRS, are carried at cost without netting the related financing that is provided by customers. The Utilities argued that financing is not equity in the accounts of the utilities so it can only be debt. Under IFRS, the deferred revenue liability for CIAC is amortized or repaid over the lives of the CIAC assets.

411. For CIAC that is under Rider I, the utility would carry the assets at regulated NBV financed at the utility's approved capital structures. The Utilities argued that there is no physical difference and no difference in business risk between CIAC financed by customers and CIAC financed under Rider I.

412. Further, currently, if the AESO deems a CIAC funded asset to be part of the system, it can order the TFO to repay the customer contributed financing. The fact that the utility can be required to refund CIAC to customers when assets are deemed part of the system is confirmation, the Utilities argued, that the financing is repayable, like debt, on demand. In situations where repayment of CIAC occurs, the utility then finances the facilities with debt and equity. However, the nature of the services provided does not change; only the method of financing so, the Utilities argued, the compensation should not change either.

413. The Utilities also commented on the UCA's criticism of the management fee for being an alleged departure from cost-based, rate-base return methodology. The Utilities noted

281 Exhibit 210.02, UCA argument, paragraph 299.

282 Exhibit 220.02, Utilities reply argument, paragraph 135-136.

283 Exhibit 220.02, Utilities reply argument, paragraph 137.

inconsistency between the UCA's position and its' own expert's view of the return margin mixed model. The Utilities argued that UCA's apparent treatment of a "return" as a non-cost item also appears to be contradicted by the proper characterization of "return" as an economic cost by Mr. Marcus, and that a management fee is no different in this respect; it is calculated on CIAC balances extant at regular intervals and thus is as fully cost-based as the regular calculation of a fair return is on investor-supplied capital.

6.2.4 How would the provision of a management fee impact risk generally, and specifically for each utility, in 2011 and 2012?

414. In argument, the Utilities stated that the management fee would have no impact on risk generally, or specifically for each utility in 2011 and 2012 and would have no impact on business risk as business risks are the same with and without the fee. The Utilities also stated that the management fee would have a *de minimus* impact on financial risk since the fee as proposed has a very minor positive impact on credit metrics.[284]

415. The UCA, the CCA and IPCAA all submitted that the provision of a management fee would reduce the Utilities level of risk.[285]

416. The UCA submitted that the risk profile of the distribution Utilities would be reduced by more than that of the transmission utilities because the distribution utilities have a higher percentage of contributed property. Mr. Marcus estimated that a distribution utility similar to ATCO Electric or Fortis would see an effective increase of about 105 basis points in ROE under Ms. McShane's proposal, while a transmission Utility like AltaLink or ATCO Electric would have an effective increase of 32-42 basis points in ROE, assuming that no customers take Rider I. The municipal distribution utilities, with their slightly lower level of contributions identified in Mr. Marcus' direct testimony, would be intermediate between these entities. Dr. Roberts suggested that the improvement in risk profile would be relatively small at 40 basis points but would be larger at 100 basis points.[286]

417. The CCA stated that, if any management fee is awarded, this must then be offset by reductions in operations and management expense and rates of return. Management, engineering and other O&M expenses for CIAC related assets are already included in the revenue requirement for the management of the utilities operational assets including those financed by customers through CIAC. Awarding of a management fee would simply provide for excess returns and cash flow to the utility thereby reducing risk.[287]

418. In reply, the Utilities argued that an award of an ROE is not risk reduction, it is risk compensation. The Utilities reiterated their position that business risk would not change and that financial risk impacts would be *de minimus*.[288]

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284 Exhibit 209.01, Utilities argument, paragraph 231 and 232.
285 Exhibit 210.02, UCA argument, paragraph 298; Exhibit 211.01, CCA argument, paragraph 62; Exhibit 212.01, IPCAA argument, paragraph 31.
286 Exhibit 210.02, UCA argument, paragraph 298.
287 Exhibit 211.01, CCA argument, paragraph 62.
288 Exhibit 220.02, Utilities reply argument, paragraph 144.

6.2.5 Have any other jurisdictions approved a fee or other mechanism to compensate shareholders for the management of contributed assets?

419. In the Utilities evidence, Ms. McShane made reference to a number of examples in which Alberta and other regulatory boards have adopted alternative approaches to compensation where the rate base/rate of return model did not provide adequate compensation. In argument, the Utilities stated that these examples were different but nevertheless support the notion that a utility is entitled to fair compensation for valuable services rendered.[289]

420. The UCA, the CCA and IPCAA all stated that they were not aware of any other jurisdiction that has approved a fee or other mechanism to compensate shareholders for the management of contributed assets.[290]

421. In its reply argument, the UCA noted the examples cited by the Utilities where regulators have awarded management fees or margin returns to regulated entities and thereby departed from the conventional cost-based rate-making construct. The UCA submitted that none of those examples is inconsistent with the UCA's position, in that all of them involve situations where a regulated entity finds itself with a rate base that is very small relative to its operating expenses, and where shareholders accordingly face operating risks that are large relative to their regulated earnings. The UCA argued that in those cases the margin return was awarded in place of a conventional rate base/rate of return profit, and not in addition to it.[291]

422. IPCAA stated that it was unaware of any evidence on the record suggesting that anything like the proposed management fee has been approved in any other jurisdiction and that a fee of the nature requested by the Utilities would appear to have no support from practices in other jurisdictions in Canada and the United States. However, IPCAA pointed out that numerous jurisdictions have adopted practices similar to the AESO's Rider I proposal and provided the examples of jurisdictions that have adopted Rider I-like approaches.

423. In its reply argument, IPCAA noted the references by the Utilities to cases where the rate base/rate of return model did not provide adequate compensation. These anecdotal references, IPCAA submitted, include Alberta-based examples such as the regulated rate tariffs of the distribution companies which are supported by special legislation. IPCAA argued that the Utilities, with the resources of eleven utility participants and an expert from Foster Associates Inc. could not produce a single example of an approved management fee for CIAC-financed assets.[292]

424. In response to IPCAA's argument, the Utilities stated that IPCAA's alleged Rider I "precedents" beg the issue that the management fee is trying to resolve and that Rider I was irrelevant to the management fee issue. The Utilities also argued that the very existence of those Rider I precedents is tacit recognition of the inherent unfairness to the Utilities for the not-for-profit turnkey construction and operation service they are obliged to provide. Finally, the Utilities noted that Rider I did not apply to gas utilities or electric distribution utilities.[293]

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289 Exhibit 209.01, Utilities argument, paragraph 233.

290 Exhibit 210.02, UCA argument, paragraph 299; Exhibit 203.01, CCA response to AUC Additional Questions, Q2; Exhibit 212.01, IPCAA argument, paragraph 32.

291 Exhibit 221.02, UCA reply argument, paragraph 107.

292 Exhibit 222.01, IPCAA reply argument, paragraph 21.

293 Exhibit 220.02, Utilities reply argument, paragraphs 145-147.

6.2.6 If a management fee is awarded, who should pay the management fee?

425. The Utilities stated that the management fee should be recovered from the same customers who now pay for the operating and maintenance costs respecting CIAC funded assets. The Utilities noted that all operating costs for CIAC financed facilities are recovered from all existing customers without distinction amongst customer classes. Finally the Utilities stated that there is no need for consideration of this matter as part of a Phase II proceeding and the recovery of the fee as proposed is a straightforward matter and no further process should be directed with respect to allocations.[294]

426. The UCA and the CCA both submitted that no management fee on contributed assets was warranted. However, the UCA submitted, should a management fee be awarded, to the extent possible, any management fees adopted should be assigned directly to customers who make the contributions. The CCA shared the UCA's opinion on this issue.[295]

427. The UCA submitted that a fee on a TFO contribution assigned to the DFO (if allowed) should be paid by all DFO ratepayers, in the same proportion as the underlying DFO rate base for property contributed to the TFO. As a practical matter, however, the UCA argued that it is difficult to see how such a scheme could be feasible at the distributor level in relation to individual customers, especially small-volume customers. For distribution contributions, which are often for relatively small projects (such as underground line extensions to subdivisions), the UCA does not consider it practical to charge individual customers. The UCA argued that the amounts could be allocated to customer classes in Phase II cases in proportion to the allocation of contributions to customer classes that is made in order to calculate the appropriate allocation of return and taxes based on total rate base.[296]

428. The CCA stated that, if Rider I was approved and if, contrary to the CCA's recommendation, a management fee were approved, all distributors who are presently required to make contributions to the TFOs for TFO investments in distribution assets exceeding the AESO's maximum investment levels should be required to adopt Rider I. This will ensure there is no double counting; first, as a result of the distributor earning a return on the amount of the contribution and second as a result of the TFO earning a management fee on the same assets.[297]

429. IPCAA argued for resolution of the underlying problem that has caused the TFOs to pursue a management fee; namely, increased customer contributions by reason of, (a) the significant increases in TFO capital costs, and (b), the lagging of the AESO's investment levels. IPCAA submitted that implementation of Rider I will contribute to resolving this underlying problem.[298] IPCAA further submitted that, should the Commission choose to approve a management fee, the determination of which customers should pay a fee of the nature of the management fee proposed by the Utilities is a Phase II general tariff application matter and should not be determined in this proceeding.[299]

294 Exhibit 209.01, Utilities argument, paragraph 236, 237 and 239.
295 Exhibit 210.02, UCA argument, paragraph 302; Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
296 Exhibit 210.02, UCA argument, paragraphs 302 and 303.
297 Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
298 Exhibit 212.01, IPCAA argument, paragraph 33.
299 Exhibit 212.01, IPCAA argument, paragraph 34.

430. IPCAA also noted that the Commission's question; namely, "should *only specific* rate payers pay the management fee on the assumption that the party who causes a cost to be incurred or who benefits from the cost incurred should pay" helps to highlight the absurdity of the Utilities' management fee proposal. If one were to point an accusing finger at the group of customers it might be claimed "caused" the so-called "need" for a management fee, the one group that might be singled out is the group of customers paying for the customer contributed assets. But how exactly could it be claimed that these customers caused this cost? They have already done everything and more that could reasonably be demanded of any customer – in this case, of course, paying the full costs of the facilities. Moreover, IPCAA argued, the amount of the cost is not something these customers necessarily have any control over.[300]

431. IPCAA submitted in reply argument that the Utilities apparently seek a decision that would prospectively deny basic intervener rights in Phase II proceedings to challenge matters such as cost causation and cost allocations. While debating the allocation of the management fee in Phase II proceedings will be an administrative burden, denying the right to be heard on this issue is not appropriate. A better solution is to deny the management fee for the reasons stated earlier in IPCAA's argument and reply.[301]

432. In reply argument, the Utilities stated that the fact that regulators have directed that the O&M relating to the operation of CIAC-funded assets should be recovered from all system users fully supports the position advanced by the Utilities in argument.[302]

6.2.7 What is the minimum amount of contributions in aid of construction that should warrant a management fee?

433. In argument, the Utilities stated that, while the proposed management fee could be applied to all contributions, their recommendation was to limit the application of the 2 per cent return to CIAC balances in excess of 4 per cent gross approved rate base (inclusive of contributions) in order to appropriately recognize the fact that other utilities in Canada also have some CIAC, albeit generally in smaller proportions.[303]

434. The UCA and the CCA did not believe that any amount or level of CIAC should warrant a management fee.[304]

435. IPCAA re-affirmed its previous submissions that the proposed management fee cannot be awarded under the *Electric Utilities Act*. IPCAA stated that should the Commission consider that it has the jurisdiction to award a fee of the nature proposed by the Utilities and that such a fee should be awarded, IPCAA recommends that the Commission use a bright line test of 10 per cent for determining if a management fee is required for the TFOs, as has been previously suggested by AltaLink Management Ltd. The bright line should be calculated by dividing the unrecovered CIAC by the total rate base of each utility.[305] IPCAA submitted that it did not agree with the Utilities four per cent bright line test for the following reasons:

[300] Exhibit 212.01, IPCAA argument, paragraph 37.
[301] Exhibit 222.01, IPCAA reply argument, paragraph 28.
[302] Exhibit 220.02, Utilities reply argument, paragraph 148.
[303] Exhibit 209.01, Utilities argument, paragraph 240.
[304] Exhibit 210.02, UCA argument, paragraph 304, Exhibit 211.01, CCA argument, paragraph 65.
[305] Exhibit 212.01, IPCAA argument, paragraphs 41 and 42.

a) A 4% bright line test contradicts the evidence of AltaLink's own witness from a prior proceeding that stated that going beyond a 10% bright line was not going to be within "a likely reasonable range", implying that less than 10% was within a likely reasonable range.

b) Even noting that the Utilities Table 1 includes a very short list of allegedly comparable utilities, the proposed 4% bright line test is well below that of FortisBC (8.8%) and Terasen Gas (6.3%) and somewhat below Maritime Electric (4.5%). A bright line used to justify an exceptionally unusual payment such as a management fee should be a boundary condition, not a median or some type of average. Clearly, FortisBC, Terasen and Maritime Electric do not receive a management fee and therefore the Utilities have a very weak argument for any harm at a bright line test below 10%.

c) The average historical CIAC as a percentage of gross rate base for the Utilities for the period 2007 to 2010 has been 8.5%. This level is still below the FortisBC level of 8.8%, further suggesting that nothing below 10% should be seen as an appropriate "bright line" for the determination of a management fee.[306] [footnotes omitted]

436. In reply argument, the Utilities submitted that the 10 per cent cut off proposed by IPCAA received no attention at the hearing and no weight should be given to IPCAA's argument in that regard. Further, the Utilities stated that, in suggesting that Dr. Cicchetti called for a 10 per cent threshold, IPCAA has seriously mischaracterized that evidence. The Utilities also stated that the current management fee proposal is made on the basis of Ms. McShane's evidence and not evidence filed in another proceeding.[307]

6.2.8 What method or formula should the Commission adopt to calculate a management fee if it chooses to award one?

437. The Utilities acknowledged that while there are likely a number of approaches that could be used to estimate a level of compensation for CIAC that would simultaneously recognize the value of services provided and the risks assumed by the Utilities, the approach advanced by Ms. McShane is the best option available. The Utilities noted that no other proposals were filed in evidence nor otherwise detailed and examined on the record of this proceeding.[308]

438. The Utilities stated that the selected methodology met Ms. McShane's objectives of constructing an approach: (1) that had a basis in financial theory, (2) the outcome of which could be objectively determined, (3) which could be applied consistently across all the Alberta Utilities, and (4) that was supported by regulatory precedent.[309]

439. The Utilities submitted that Ms. McShane presented what are really two approaches which proceed from different premises but yield the same quantum of compensation. The first proceeds on the premise that CIAC represents a liability akin to debt, which decreases the effective equity ratio of the Utilities. In the absence of CIAC, the assets would be financed with interest bearing debt. The amount of compensation that is reasonable for CIAC funded assets is derived from the increase in the cost of equity that results from the reduction in the Utilities'

306 Exhibit 212.01, IPCAA argument, paragraph 46.
307 Exhibit 220.02, Utilities reply argument, paragraph 150, 151.
308 Exhibit 209.01, Utilities argument, paragraph 244.
309 Exhibit 209.01, Utilities argument, paragraph 245.

effective equity ratio due to the presence of debt-like CIAC. The amount of CIAC compensation is equivalent to the return required for bearing incremental financial risk.

440. The Utilities noted that Ms. McShane explained that the same estimate of a reasonable margin is arrived at without invoking financial risk by applying the "OEB Methodology" under which it is assumed that, in the absence of CIAC, the utilities financed all of their assets at the same overall return (their opportunity cost of capital). To recognize that ratepayers are providing an interest-free loan to the Utilities, ratepayers are credited with the utility market cost of debt. The effective compensation to the utilities for CIAC is limited to the difference between their overall cost of capital and their cost of debt.[310]

441. While alternatives such as a return margin were considered by Ms. McShane, the Utilities submitted that the selected methodology was chosen because it could be easily applied generically across utilities and it appropriately focused on the assets and resulted in a sharing of benefits of the CIAC among customers and utilities.[311]

442. In response to Mr. Marcus' criticism of the quantum of the proposed management fee[312] as disproportionate to the impact on operating leverage and additional risk posed by CIAC, the Utilities stated that examining the impact on operating leverage alone does not suffice. It is not a benchmark for reasonableness or fairness of the proposed fee. The Utilities noted that the Utilities are exposed to operational, regulatory and market risks with respect to CIAC financed assets and that these risks are not easily quantifiable.

443. Further, the Utilities submitted that the proper context for the evaluation of the reasonableness of a management fee is not solely the risks borne with respect to the CIAC-funded assets, but also fairness in light of the value of service provided.

444. In response to parties'[313] submissions that a small percentage addition to O&M expense could be employed as a management fee, the Utilities stated that such an approach should be rejected and that any suggestion that what is being managed for contributed property is limited to operating and maintenance expense misrepresents and marginalizes the functions that the Utilities perform in relation to CIAC-financed assets.[314]

445. The UCA opposed the imposition of a management fee in any form and had no opinion on what formula should be applied or collection method adopted.[315]

446. The CCA submitted that, while it did not support any management fee on contributed assets, the concept put forward by the Utilities is that it is required to compensate the utility for planning, managing and operating the contributed assets. Accordingly, the management fee, if approved, should be determined as a per cent of the O&M expenses associated with contributed assets. The CCA further submitted that the determination as to whether a management fee

310 Exhibit 209.01, Utilities argument paragraph 246.
311 Exhibit 209.01, Utilities argument, paragraph 248.
312 Transcript, Volume 6, page 815, lines 15-23.
313 Exhibit 130.01, Mr. Marcus' response to Utilities-UCA-58(c)), Exhibit 202.01, IPCAA response to AUC Additional Questions, Q4; Exhibit 203.01, CCA response to AUC Additional Questions, Q4.
314 Exhibit 209.01, Utilities argument, paragraph 254.
315 Exhibit 210.02, UCA argument, paragraph 305.

applies or not should be made at the time of the GRA, on a forecast basis, having regard to a threshold.[316]

447. IPCAA stated that, if a management fee were to be approved, any fee should only be calculated on any amounts that exceed the 10 per cent bright line test. Furthermore, it should be calculated on the basis of the service of managing property and should not be based on the value of the property itself.[317] IPCAA further stated that the idea that the Utilities are providing the service of managing the CIAC assets without compensation is wrong. Any cost incurred is compensable and is compensated for as is any reasonable and prudent cost.[318]

6.2.9 Should other forms of no-cost capital also be eligible for a management fee? What is the rationale for including or excluding other forms of no-cost capital?

448. The Utilities submitted that the management fee proposal was to apply only to CIAC and that other forms of no-cost capital would not be eligible for, or included in, the calculation of the management fee. The Utilities noted that there is a distinction to be made between CIAC and other forms of no cost capital. CIAC balances, the Utilities argued, relate to long-term assets over which the Utilities provide valuable services and bear risks. Other forms of no cost capital arise as a result of timing differences between the incurrence and recovery of costs and do not involve the fairness issue related to CIAC financed assets and, consequently, do not warrant treatment analogous to that requested for CIAC.[319]

449. In reply argument, the Utilities added that the management fee was based in part on the business risks inherent in offering a not-for-profit turnkey construction service and not-for-profit operations and maintenance service and that these services were very different from the business risks associated with managing deferred taxes and depreciation reserves.[320]

450. The UCA submitted that it did not accept the premise that a management fee is appropriate or necessary as compensation related to the management of CIAC or any other form of no-cost capital, or accumulated depreciation. Any proposal to give shareholders a return on amounts that they have not actually invested in the business is misconceived and inconsistent with the principles of cost-based rate-making.[321]

451. The CCA considered that no management fee should be allowed on no-cost capital. The CCA considered that the fair return and revenue requirement awards have, and do, take into account issues surrounding no-cost capital. Customers currently pay all costs associated with no-cost capital including asset management. The CCA views no-cost capital as reducing utility risk, not increasing risk.[322]

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316 Exhibit 203, AUC-CCA-04.
317 Exhibit 212.01, IPCAA argument, paragraph 47.
318 Exhibit 212.01, IPCAA argument, paragraph 49.
319 Exhibit 209.01, Utilities argument, paragraphs 257 and 258.
320 Exhibit 220.02, Utilities reply argument, paragraph 156.
321 Exhibit 210.02, UCA argument, paragraph 306.
322 Exhibit 211.01, CCA argument, paragraph 67.

452. IPCAA submitted that, as it had previously discussed, the Commission does not have the power to award compensation for costs for which no utility investment has been made over and above what is needed to reimburse the utility for its reasonably incurred costs.[323]

6.2.10 **Assuming that the balance of CIAC changes on an annual basis, what method or formula should the Commission adopt to calculate a management fee and include the fee in base rates, it if chooses to award one? When should a management fee be instituted if it is approved?**

453. The Utilities summarized the calculation of the annual management fee in their argument, as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilites would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[324]

454. The Utilities noted that, if the Commission approves Rider I, the annual amount of CIAC eligible for the management fee would be dependent on the extent to which customers opt for Rider I, which is uncertain. Consequently, the Utilities recommended the implementation of a deferral account for the TFOs which would true up the difference between the actual and forecast management fee.[325]

455. For those utilities who are, or will be, subject to PBR, the Utilities recommended the calculation of the annual management fee described above be modified to use the previous year actual mid-year balances as, for other than the PBR base year, there may not be an approved forecast mid-year rate base balance.[326] The Utilities submitted that the management fee should be approved to be effective January 1, 2011.[327]

456. The UCA's position was that no management fee is warranted, and so it did not offer an opinion on how the Commission should calculate a fee that the UCA does not believe should be imposed in any form or in any amount.[328]

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323 Exhibit 212.01, IPCAA argument, paragraph 54.
324 Exhibit 209.01, Utilities argument, paragraph 260.
325 Exhibit 209.01, Utilities argument, paragraph 261.
326 Exhibit 209.01, Utilities argument, paragraphs 262 and 263.
327 Exhibit 209.01, Utilities argument, paragraph 264.
328 Exhibit 210.02, UCA argument, paragraph 309.

457. IPCAA submitted that, should the Commission approve a management fee against IPCAA's recommendations, IPCAA submits that the management fee should be:

a) Calculated only on any amounts that exceed the 10% bright line test; and

b) Calculated on the basis of the service of managing property and should not be based on the value of the property itself.[329]

458. In reply argument, IPCAA reiterated its submission that the Commission is without jurisdiction under the *Electric Utilities Act* to award a management fee as requested by the Utilities. Further, IPCAA submitted that, should the Commission conclude that it does have jurisdiction to award some form of fee for management services as requested by the Utilities, and that such a fee is warranted, IPCAA submits that it should only be instituted after completion of a Phase II proceeding of the AESO or relevant DFO.[330]

459. In its reply argument, the Utilities stated that it would be grossly unfair to the Utilities to deny the recovery of the management fee now because the uptake on Rider I may not be known for some months after a decision is released.[331]

6.3 Commission findings

Jurisdiction to award a management fee

460. The Commission has the obligation to ensure that the rates it establishes are just and reasonable in accordance with Section 121(2)(a) of the *Electric Utilities Act*, Section 36(a) of the *Gas Utilities Act* and Section 89(a) of the *Public Utilities Act*.

461. In fixing just and reasonable rates, the *Gas Utilities Act* (Section 37) and the *Public Utilities Act* (Section 90) require that the Commission determine a rate base on which to fix a fair return by giving due consideration to the cost of the property when first devoted to public use and to the prudent acquisition cost to the owner of the utility, and to necessary working capital. In the *Electric Utilities Act*, return is considered to be a subset of the "costs and expenses associated with capital *related to the owner's investment in the electric utility*" (Section 122(1)(a)) and is specified as a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)).

462. The process by which the Commission sets rates was described by the Supreme Court in *Northwestern Utilities Ltd. v. City of Edmonton*[332] and cited in *Stores Block*:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also

[329] Exhibit 212.01, IPCAA argument, paragraph 55.
[330] Exhibit 222.01, IPCAA reply argument, paragraph 34.
[331] Exhibit 220.02, Utilities reply argument, paragraph 158.
[332] *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684 at page 691; *Stores Block, supra*, paragraph 65.

> **determined in Phase I**. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered. [emphasis added]

463. This approach to approving the recovery of a utility's prudent costs and awarding a fair return on the equity portion of a utility's investment is the basis of the cost of service regulation framework that has been employed by the Commission for decades.

464. The legislature has recognized that there are situations where return on rate base may be inadequate to allow for proper compensation. Section 6(1)(b)(i) of the *Regulated Rate Option Regulation*[333] promulgated under the *Electric Utilities Act* requires the Commission to approve a reasonable return (which is not tied to investment but rather to the obligation to provide service) as well as a risk margin (Section 5) that compensates for a number of specific risks.[334] Neither the *Electric Utilities Act* nor the *Gas Utilities Act* contain such provisions.

465. Interveners generally argued that the relevant legislation and cost of service regulation principles provide for the entire compensation scheme for the Utilities, which consists only of a return on the capital invested in rate base and the recovery of prudent costs. The interveners characterized the management fee as a request for additional return or profit, which they argued the Commission was not authorized to grant under a strict interpretation of the statutes together with traditional cost of service regulatory principles.

466. In general, the Commission agrees with this interpretation of the statutes. However, the Commission considers there are circumstances, such as the "vanishing rate base" scenario cited by some interveners, where the return on rate base approach may not allow for sufficient return to provide for just and reasonable rates. In such situations, the Commission considers that case law provides it with the authority to implement a mechanism, which might be in the form of a management fee, in order to ensure that just and reasonable rates are achieved.

467. As noted above, the Utilities cited the Supreme Court of Canada's decision in *Northwestern 1961* in support of their *quantum meruit* argument. In that case, the Supreme Court of Canada found that the Commission's predecessor had jurisdiction to fix just and reasonable rates, which included fixing rates to allow for transitional losses between the date of application and the date of decision. The Court concluded that, even in the absence of any statutory provision, there is an obligation at common law for ratepayers to pay for utility service on the basis of *quantum meruit* as part of the jurisdiction to ensure that tolls are at all times just and reasonable.

468. In *Northwestern 1961*, the authority of the Commission's predecessor to establish a "purchased gas adjustment clause" was at issue. This clause was essentially a variance account mechanism that permitted the utility to recover from consumers in the future amounts the utility had to pay for gas that proved more expensive than the utility's estimates (and to refund amounts

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333 AR 262/2005.

334 Similarly, Section 5(a) of the *Default Gas Supply Regulation*, AR 184/2003 under the *Gas Utilities Act* provides for "...a reasonable return on costs deemed eligible by the Commission, excluding the cost of gas that is provided and delivered..."

to consumers if the estimates proved to be greater than the actual cost). While not specifically provided for in the relevant statutes, the jurisdiction of the Commission's predecessor to approve such a mechanism was upheld by the Court. In particular, at pages 406-407 of its judgment, the Court stated that the authority flowed from the power to set just and reasonable rates which would yield a fair return:

> With great respect, however, the proposed order would be made in an attempt to ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in that subsection and to comply with the Board's duty to permit this to be done. How this should be accomplished, when the prospective outlay for gas purchases was impossible to determine in advance with reasonable certainty, was an administrative matter for the Board to determine, in my opinion. This, it would appear, it proposed to do in a practical manner which would, in its judgment, be fair alike to the utility and the consumer.
>
> As pointed out by Porter J.A., s. 67(5) does not touch the matter and this the respondent concedes, but the Board has not assumed to act under that subsection. Rather **did it propose to make the order under the powers given to it and the duty imposed upon it by the sections to which I have referred to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2).** [emphasis added]

469. The Commission considers that this case supports the proposition that, in certain circumstances, in order to satisfy its duty to set just and reasonable rates, the Commission has the jurisdiction to approve compensatory schemes that are not specifically provided for in the statutes to ensure that a fair return is realized.

470. The Commission will now consider the questions as to whether: (1) the rate of return compensation scheme set out in the legislation is insufficient to provide for just and reasonable rates given the current levels of CIAC, and (2) if so, whether the proposed management fee is warranted.

471. It should be noted that this was not the manner in which the Utilities framed their argument in support of the management fee. The Utilities' primary argument was that the principle of *quantum meruit* requires that the services that the Utilities are providing with respect to the CIAC-financed assets be compensated. The Utilities also justified the management fee by submitted evidence related to increased risk (financial, operating leverage and business risk).

472. Therefore, with respect to the first question, the Commission will consider whether the arguments of the Utilities with respect to *quantum meruit* and increased risk associated with CIAC support the conclusion that the rate of return compensation scheme is insufficient.

Is the rate of return compensation scheme set out in the legislation insufficient to provide for just and reasonable rates?

473. As discussed above, the *Electric Utilities Act* and the *Gas Utilities Act* provide for compensation consisting of a return on utility investment and recovery of prudent costs. The Utilities submitted that where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities argued that CIAC levels are significantly higher in Alberta than the industry average and, as a result, "that paradigm does not provide fair or any compensation in relation to services provided and risks

borne in relation to CIAC-funded assets."[335] The Utilities stated that the proposed management fee will augment the conventional model, and also stated that the proposed management fee provides for a margin or fair compensation for all of the services they render relating to assets that are constructed, owned and operated by the Utilities, but which are financed by customers.

474. Interveners argued that the statutory and regulatory schemes do provide for sufficient compensation. The UCA submitted that the cost-based rate-making principle says that utilities should be entitled to charge rates that provide them with a reasonable opportunity to recover their prudently incurred costs, including a fair return on the capital they have invested in the business, but that they are not entitled to charge rates that are higher than that. The UCA argued that approval of the management fee proposal would result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable.[336]

475. In determining whether rates are not just and reasonable without specific compensation for services the Utilities provide in respect of the CIAC-funded assets, given the current levels of CIAC, the Commission will now address the main arguments cited by the Utilities namely:

- *quantum meruit* for value of services rendered
- risk considerations

Value-added services and the concept of *quantum meruit*

476. The Utilities submitted that the services for which they are requesting compensation by way of a management fee include the construction, operation and maintenance of CIAC funded assets. While the interveners argued that the Utilities are being fully compensated for the provision of services, the Utilities replied that merely covering out-of-pocket costs is not compensation for the provision of value-added services.[337]

477. The Utilities appear to suggest that the concept of *quantum meruit* provides both the jurisdiction and the requirement that they be compensated above cost for these services, which they have also referred to as the "value-added" services. Thus, the Commission considers that determining the value of the services provided by the Utilities in respect of the CIAC-funded assets is fundamental to assessing the Utilities' *quantum meruit* argument.

478. The Commission finds that the Utilities have not established that they are providing any "value-added" services specifically associated with CIAC-funded assets. The Utilities argued that the construction, operation and maintenance of CIAC-funded assets is a value added service. The Commission does not agree. The construction, operation and maintenance of the assets owned by the utility are necessary for the provision of electric utility service, whether the assets were funded by CIAC or not. The Utilities have proffered no evidence of having to provide any services beyond the delivery of the electric utility service that is required, pursuant to their obligation to serve, and for which they are compensated through the rates approved by the Commission.

335 Exhibit 220.02, Utilities reply argument, paragraph 111.
336 Exhibit 221.02, UCA reply argument, paragraph 100.
337 Exhibit 220.02, Utilities reply argument, paragraph 132.

479. Further, the Commission considers that the Utilities have not provided any evidence by which the Commission can quantify these "value-added" services, over and above the costs incurred for the provision of electric utility service, for which they are compensated through the rates approved by the Commission.

480. The Utilities cited *Northwestern 1961* in support of the *quantum meruit* nature of their claim. However, the Commission finds that the Utilities are unable to specifically quantify the actual cost of the "value added" services, other than to say that reasonable compensation can be derived from "the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC."[338] In contrast, in *Northwestern 1961*, the transitional amounts that the Commission's predecessor determined the utility should be compensated for were clearly identifiable and quantifiable amounts incurred by the utility. This is in distinct contrast to the Utilities' request for compensation.

481. Nonetheless, the Utilities' proposal that the management fee should be equivalent to the increase in the cost of equity that results from the reduction in the Utilities' effective equity ratio due to the presence of debt-like CIAC appears to argue that the Utilities incur an opportunity cost by being required to construct, operate and maintain CIAC funded assets. However, the Utilities recover the prudently incurred costs to construct, operate and maintain the CIAC funded assets as well as an allowed return on the working capital required to fund these costs through the rates approved by the Commission. Consequently, the Commission does not agree that the Utilities incur an opportunity cost in being required to fund the construction, operation and maintenance of the CIAC funded assets.

482. On a final note, when one looks at the contributed capital scheme and the notion that customers must contribute some portion of the initial start up costs, one must also consider what benefit the utility receives. If it was not for the customer's contribution, the utility would not have that customer nor the opportunity to invest in the rate base assets not funded by CIAC that are required to provide service to that customer.

483. The Commission finds that it has not been established that the services provided by the Utilities in respect of CIAC-funded assets represent a value added service that is in addition to the utility services which are compensated under the statutory scheme. Nor has it been established that the services have any quantifiable value. Accordingly, the Commission finds that there is no evidence that the provision of services in respect of CIAC-funded assets requires any compensation through a management fee or results in rates that are not just and reasonable.

Risk considerations

484. The Commission will now address the question of whether the Utilities rates are just and reasonable considering the argument that the Utilities incur risks related to CIAC for which they are not adequately compensated.

485. The Utilities argued that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC), the higher is the financial risk.[339] The Utilities stated that operating leverage

[338] Exhibit 86.01, opinion on management fee and Rider I, lines 48-51.
[339] Exhibit 86.01, page 13, lines 361-364.

refers to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[340]

486. The Utilities also stated that, as set out in CCA-Utilities-31, there are business risks and liabilities other than the operating leverage risk to which the Utilities are exposed. The Utilities listed these business risks as:[341]

- Operational risk (liabilities for):
  - i. Damages to company facilities by others or weather
  - ii. Public injury as a direct result of company operations
  - iii. Environmental contamination resulting from a release of contaminates
  - iv. Release of natural gas causing fire or explosion as a direct result of company operations
  - v. Service outages which result in customer property damages and/or injury as a result of equipment failure
  - vi. Decommissioning and asset retirement liabilities
- Regulatory risk:
  - i. unfavorable regulatory decisions
  - ii. compliance with regulation and legislation
  - iii. unforeseen changes to provincial or federal legislation affecting the company operations
- Other business risks:
  - i. Forecasting operating and maintenance costs
  - ii. Franchise loss
  - iii. Weather
  - iv. Market loss
  - v. Fraud

487. In her evidence Ms. McShane stated that the presence of CIAC increases the effective debt ratio (or alternatively, decreases the effective equity ratio) and that CIAC represents a liability that is akin to debt, albeit interest-free.[342] Further, Ms.McShane stated that the lower the equity ratio, the higher the financial risk, and the higher the cost of equity for a given level of business risk.

488. The Utilities stated that the higher level of CIAC relative to total rate base, the higher is the operating leverage, or sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs. Ms. McShane provided an example in Table 2 of her evidence of the sensitivity of the ROE to an unanticipated change in O&M expense. Ms. McShane stated that the example showed that an unanticipated increase in O&M expense reduced the actual ROE below the allowed ROE by a wider margin for a utility with CIAC than it does for a utility with no CIAC and stated that greater CIAC introduces greater potential volatility in actual earnings.

489. Mr. Marcus submitted that in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has some theoretical validity since CIAC can create incremental operational risk. The Commission agrees with this observation, as further discussed below.

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340 Exhibit 86.01, page 13, lines 364-366.
341 Exhibit 135.02, CCA-Utilities-31.
342 Exhibit 86.01, page 14, lines 381-383.

490. The Commission notes Ms. McShane's rebuttal evidence in which she acknowledges that the proposed management fee exceeds the likely deviation from the allowed return due to higher operating leverage, and includes compensation for other risks as well as the value of services provided.[343] Given the Commission's determination that there are no value added services provided by the Utilities with respect to the CIAC-funded assets, the Commission does not agree that the incremental level of business and financial risk associated with these assets, on its own, supports the management fee proposed by the Utilities.

Management fee conclusions

491. The Commission determined above that the services related to CIAC-funded assets are not distinct from the utility services compensated for under the statutory scheme and that the incremental level of risk associated with these assets, on its own, does not support the management fee proposed by the Utilities. Consequently, the Commission does not accept the management fee proposal.

492. Additionally, the Commission considers that the concept of a management fee should be viewed in the context of the Alberta regulatory framework. For example, IPCAA noted the potential "double charging" for DFO customers that may occur if the TFOs are allowed to earn a management fee on assets paid for by a customer contribution. In this case, DFO customers would pay the management fee to the TFO (that the DFO would pass on to its customers), as well as the return to the DFO for the contribution made to the TFO, because the contribution would become part of the DFO's rate base.[344]

493. This is of particular concern in situations in the electric utility industry where the TFO and DFO are part of the same larger corporate entity. For ENMAX, EDTI and ATCO Electric TFOs, the corporate shareholder earns a rate of return on CIAC assets where the CIAC funding comes from the DFO affiliate, and the TFO affiliate would earn a management fee on those same assets. In her evidence, Ms. McShane expressed her view that corporate affiliations should not be a determinant of the appropriate compensation for CIAC and that compensation for CIAC should be provided to the regulated entity that constructs, owns, operates and manages the underlying assets and provides the related services.[345]

494. The Commission does not agree with the position advanced by Ms. McShane and the Utilities in this instance. The Commission considers that, for the corporate shareholder to receive a return on transmission assets funded by the DFO, because the contribution is added to the DFO's rate base, as well as a management fee provided to the TFO on those same transmission assets, would result in an unwarranted additional return to the corporate shareholder.

495. Nonetheless, even though the management fee proposed by the Utilities is not warranted, the Commission agrees with the Utilities that CIAC-funded assets contribute to business risk. In general, business risk would be expected to rise in proportion to assets. The Commission agrees with the Utilities that, without an increase in equity, CIAC-funded assets would cause an increase in financial risk and operating leverage risk.

343 Exhibit 152.04, McShane rebuttal evidence on management fee, lines 378-385.
344 Exhibit 212.01, IPCAA argument, paragraph 29.
345 Exhibit 86.01, page 14, lines 381-383.

496. As outlined in Section 5 above, it has been the practice of the Commission and its predecessor to adjust for any differences in risk among the utilities by adjusting their individual equity ratios. The Commission has reaffirmed its adherence to this approach in this decision.

497. In this regard, the Commission notes that the equity ratios awarded in Decision 2009-216 were determined by examining the credit metrics for a sample of utilities with an A credit rating. The sample utilities used in Table 12 of Decision 2009-216 were exclusively Alberta utilities and therefore reflected the typical level of contributed assets of the Alberta utilities, as of 2009. These Alberta utilities were able to achieve A credit ratings at their observed credit metrics despite having a certain amount of CIAC-funded assets.

498. Furthermore, in the case of AltaGas, the EUB explicitly recognized in Decision 2004-052 that a high level of customer contributions increases business risk, when it set the equity ratio of AltaGas in the 2004 GCOC proceeding. In that decision, the EUB stated:

> 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.
> [...]
> Considering all of the above, the Board concludes an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.[346]

499. As the UCA pointed out in its argument, no utilities have been downgraded since the 2009 proceeding and, therefore, the Commission considers that the equity ratios awarded in Decision 2009-216 adequately reflected all of the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets.

500. In this decision, the Commission continued the equity ratios awarded in 2009 for 2011 and 2012, with the exception of ATCO Electric TFO, AltaLink TFO, and ATCO Pipelines. Based on the data provided in Attachment A of Ms. McShane's evidence, CIAC as a percentage of gross rate base (inclusive of contributions) of the Alberta Utilities, in total, is expected to decrease from 17 per cent in 2009 to 15 per cent 2012.[347]

501. Specifically, the data provided in Attachment A of Ms. McShane's evidence shows that, while the level of CIAC for electricity and gas distributors is forecast to decrease from 21 per cent of gross rate base in 2009 to 18 per cent in 2012, the CIAC for TFOs is expected to increase from 9 per cent of gross rate base in 2009 to 12 per cent in 2012.[348] The Commission considers that addressing factors such as the maximum investment levels of the electricity and gas distributors will help to further reduce the amount of CIAC-funded assets in the future. In that regard, in Decision 2011-134, the Commission recently increased maximum investment levels substantially for ATCO Electric.[349]

502. With respect to the TFOs, the Commission considers that the approved Rider I will likely result in a reduction in the CIAC levels of the TFOs. Further, the Commission has initiated the

346 Decision 2004-052, page 53.
347 Exhibit 86.01, Kathleen McShane opinion, Attachment A, PDF page 214.
348 Ibid.
349 Decision 2011-134, Section 5.3.

Electric Transmission Contribution Policy proceeding[350] in which it will address aspects of the AESO's customer contribution policy. The outcome of this proceeding will likely affect the level of CIAC for the TFOs in Alberta.

503. In light of these factors, the Commission considers that the equity ratios awarded in this decision for 2011 and 2012 adequately reflect the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets. On a go-forward basis, the Commission will consider any concerns related to the level of CIAC-funded assets on a utility-specific basis and, if necessary, adjust the equity thickness for the utilities.

7 Rider I matters

7.1 Background

504. Following concerns expressed by certain industrial customers with respect to the up-front payment of construction contributions for system access service (i.e. transmission) connections, the AESO proposed a new "Rider I" to finance these contributions. Rider I would allow customers to pay the construction contribution principal in equal monthly amounts, over a period of up to 20 years, plus a carrying cost (similar to an interest charge) on the unpaid contribution balance. Rider I would also allow for contributions that were previously paid for transmission facilities to be refunded and then re-paid through Rider I.[351] Rider I would only be available to fund contributions to transmission facility owners (TFOs).

505. The AESO first proposed Rider I in its 2010 GTA.[352] In that proceeding, the Commission determined that Rider I should be considered in conjunction with the management fee matter and stated in Decision 2010-606 that it "makes no findings in respect of the merits of Rider I at this time...Rider I will be considered in association with the management fee in the upcoming 2011 Generic Cost of Capital proceeding."[353]

506. The Utilities supported Rider I[354] because they are concerned about the increasing levels of customer contributions, including contributions to the TFOs by the distribution facility owners (DFOs).[355] Contributions by DFOs to transmission substation costs result in a transfer of rate base from a transmission utility to a distribution utility. High levels of contributed assets reduce the amount of a utility's rate base that can earn a return on capital for rate making purposes.

507. In addition to supporting Rider I, the Utilities proposed a management fee as compensation for managing the contributed assets.[356] This is discussed in detail in Section 6 above.

350 Proceeding ID No. 1162.

351 Exhibit 77.02, Appendix B – Previously-Filed Evidence on Amortized Construction Contribution Rider I, page 36 of 58, paragraph 191, PDF page 32.

352 Alberta Electric System Operator, 2010 ISO Tariff Application, Application No. 1605961, Proceeding ID No. 530.

353 Decision 2010-606, page 58, paragraph 302.

354 Exhibit 209.01, written argument of the utilities, page 67, paragraph 266.

355 Exhibit 86.01, opinion on management fee and Rider I, pages 6-7.

356 Exhibit 86.01, opinion on management fee and Rider I, pages 2-3.

7.1.1 Current contribution mechanics

508. A connecting customer must provide financial security up to the amount of the TFO's maximum investment level. This financial security must be in the form of a guarantee, cash deposit or irrevocable letter of credit from a Canadian chartered bank, credit union, trust company or other financial institution with a minimum senior unsecured long-term debt A- credit rating. The financial security must also be to the satisfaction of the TFO.

509. If the costs of the connection project exceed the maximum investment level, the customer must provide a construction contribution in the amount of the financial obligation above the maximum investment level. The construction contribution must be paid by way of electronic funds transfer or wire transfer to the TFO.

510. After the commencement of commercial operation of the connection project, the TFO returns any security held for the connection project, the construction contribution is not returned to the customer, but held by the TFO as part of its contributions in aid of construction (CIAC).

7.1.2 Mechanics of Rider I

511. As in the current contribution regime, until a connection project reaches commencement of commercial operation, the customer would be required to provide financial security for all the costs incurred by the TFO up to the maximum level of utility investment allowed by the Commission. For expenditures above the maximum utility investment allowed by the Commission, the customer would still be required to provide a cash contribution to the TFO to the full amount of the connection project. However, if Rider I were in effect, the customer may request that this cash contribution be repaid to the customer by the TFO after the commencement of commercial operation.[357]

512. The contribution refund would then be converted into an obligation to the AESO and paid by way of monthly payments to the AESO under Rider I. The Rider I amounts collected by the AESO would be included in the AESO's revenue forecast and would therefore offset amounts to be collected from other market participants. The amount of the contribution refund would be added to the TFO's capital invested in rate base since the balance of the TFO's no cost capital would be reduced by that amount. Because the amount of the refunded contribution would add to the TFO's capital invested in rate base, the TFO's revenue requirement would increase. This higher revenue requirement would be recovered through Rider I payments from the AESO to the TFOs.

513. The changes in the TFO's revenue requirement would be reflected in the TFO tariff paid by the AESO[358] and recovered by the AESO through Rider I.

514. The calculation of monthly Rider I payments would be made in accordance with a formula set out in Rider I, which is designed to exactly match the cost differential in the TFO's revenue requirement that will result from the elimination of the contribution. The AESO

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[357] The request to have the contribution refunded under the Rider I regime could be made by a customer at any time, and the amount of the contribution refund would be calculated as the amount that has not yet been recovered through transmission rates.

[358] Exhibit 77.02, Appendix B – Previously-Filed Evidence on Amortized Construction Contribution Rider I, AML.AESO-002(c), PDF page 12 of 35.

submitted that Rider I payments would leave the TFOs unaffected, as they can continue to file their revenue requirements for approval with the Commission.[359]

515. The AESO submitted that the fundamental purpose of Rider I is to allow the highest value use of capital by the entities involved.[360] It would free up customer capital to be invested in their businesses, while the transmission connection asset would be financed by the TFO's capital. The proposed Rider I would provide:

> ...market participants with an option to amortize and pay construction contributions over a period of up to 20 years, rather than in full prior to construction... Rider I is proposed to be available for system access services under both Rate DTS [demand transmission service] and Rate STS [(generator) supply transmission service], and is designed to address the financial aspects of the proposed approach, including risk of default, such that market participants who do not select the option are unaffected by those who do.[361]

516. When asked by the Commission panel if there is a concern that Rider I could potentially reallocate resources in the economy in a sub-optimal manner, the AESO's witness stated that:

> Ultimately Rider I would end up in some reallocation of resources. It seems to us when we've talked about it that it should result in a more optimal allocation of resources in that the ownership and operation of the facilities will be put to the party that has the expertise in that area.[362]

517. The AESO submitted that the principle difference between the form of Rider I proposed in this application and Rider I as it was originally proposed in the AESO's 2010 GTA, is the requirement for the customer to provide financial security in the amount of the construction contribution remaining outstanding during the Rider I term.[363] The AESO indicated that the financial security would be in the form of a letter of credit or other financial security from a financial institution.[364] There would be no requirement for financial security from a DFO regulated by the Commission.[365] The AESO submitted that the requirement for financial security would eliminate any risk of default arising from utilization of Rider I.[366]

518. The AESO witness indicated that Rider I is in the public interest because:

> The proposed implementation of Rider I, together with the provision of financial security ... ensures that other market participants are not harmed by Rider I. In addition, Rider I facilitates the most efficient use of capital for both market participants and transmission facility owners. The AESO therefore believes Rider I contributes to economic efficiency, which is in the public interest.[367]

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359 Transcript, Volume 4, page 479, line 10 to page 489, line 25.
360 Exhibit 77.01, AESO evidence on Rider I matters, page 2 of 8, paragraph 12.
361 Exhibit 77.02, page 58 of 268, paragraph 290, PDF page 2.
362 Transcript, Volume 4, page 505, lines 10-15.
363 Alberta Electric System Operator, 2010 ISO Tariff Application, Application No. 1605961, Proceeding ID No 530.
364 Transcript, Volume 4, page 476, lines 11-13.
365 Exhibit 77.01, AESO evidence on Rider I matters, Appendix A, subsection 3(1).
366 Exhibit 77.01, AESO evidence on Rider I matters, page 4 of 8, paragraph 23.
367 Transcript, Volume 4, page 473, line 20 to page 474, line 2.

7.2 Views of the parties

519. IPCAA fully supported Rider I as proposed by the AESO in this proceeding and recommended that it be approved for immediate implementation. IPCAA also requested that Rider I be made available for all transmission-connected customers, including customers who contract directly with the AESO and those who contract with a DFO, which "flows through" the AESO's tariff charge to the customer. Therefore, IPCAA recommended that, should the Commission approve Rider I, that it also direct the DFOs to also implement Rider I in a timely fashion.[368]

520. As further discussed below, the Utilities, the UCA and the CCA supported Rider I with some exceptions and qualifications.

7.2.1 Risk of default

521. One of the primary concerns with Rider I as originally proposed in the AESO's GTA was with the risk borne by all customers if a Rider I customer defaulted. In his testimony, the AESO witness stated:

> So my understanding is that the risk lies with the AESO and other ratepayers. During the construction phase of that line, we do require the market participant to put up financial security for the cost of the line, even that amount covered by investment. So that covers any risk up to the commercial operation date, even if the line is fully covered by investment.[369]

522. The AESO submitted that the risk of default has been fully mitigated by its right to deny a customer's request for Rider I, the availability of Rider I only after commercial operation of the connection facilities, and the requirement of a customer to provide security for any unrecovered construction contribution during the Rider I term.[370]

523. The AESO acknowledged that, in the event that the customer defaulted on its Rider I payments and the financial institution that provided the financial security was failing at the same time, the unrecovered balance from that customer would be recovered from the other customers.[371] However, the AESO also stated:

> So it seems like that potential eventuality of simultaneous collapse of the market participant and the party providing their financial security without foreknowledge of the AESO, that seems like an extremely small risk.[372]

7.2.2 Mandatory requirement of Rider I for DFOs

524. The UCA supported Rider I as proposed by the AESO with one qualification. The UCA submitted that for a DFO Rider I should be mandatory if it has the same tax status as the TFO and particularly if it is part of the same company as the TFO.[373] The UCA stated that because the DFO is likely to have a greater equity thickness than the TFO, distribution rate payers would be

368 Exhibit 212.01, IPCAA argument, page 19, paragraphs 71-72.
369 Transcript, Volume 4, page 516, lines 5-11.
370 Exhibit 206.01, AESO argument, page 2, paragraph 8.
371 Transcript, Volume 4, page 477, line 23 to page 478, line 14.
372 Transcript, Volume 4, page 500, lines 3-6.
373 Exhibit 210.02, UCA argument, pages 65-66, paragraph 324.

better off if the DFO's contribution were financed by Rider I.[374] Second, the UCA submitted that this recommendation is critical if the Commission approves a management fee because of the possibility of "double-dipping"; that is, the scenario in which a TFO would have the asset in rate base, while a DFO owned by the same parent company was collecting a management fee on a contributed asset. The UCA also stated that if the Commission rejected the management fee, as recommended by the UCA, most of its concerns in this area would be alleviated. Nonetheless, the UCA argued, in principle, if the TFO has a lower cost of capital than the DFO, there would still be an advantage to customers if the DFO opted for Rider I, even in the absence of a management fee.[375]

525. The CCA recommended that Rider I be approved as filed by the AESO subject to adequate "prudential requirements" (financial security).[376] The CCA also submitted that there would be a need for further hearing process to adjust TFO rates if the Commission approves Rider I. Like the UCA, the CCA also recommended that, for DFOs, Rider I should be mandatory and suggested that this may entail adjustments to DFO revenue requirements as well.[377]

526. In response to the submission by the UCA that Rider I should be mandatory for all DFOs, the Utilities stated that there is no rational basis for creating a distinction between standalone and integrated utilities. The Utilities submitted that all utilities are subject to the standalone principle; and therefore corporate affiliations should not necessitate use of Rider I any more than they should be a determinant of the appropriate compensation for CIAC.[378] Therefore, the Utilities submitted that Rider I should be optional for all market participants.

7.2.3 Option to enter into and leave Rider I

527. The Utilities supported Rider I as proposed by the AESO with the following modification. The Utilities submitted that the option to convert to Rider I should be a one-time option to be exercised by a market participant either within six months of commencement of commercial operation for new projects or within six months from the date Rider I becomes available for existing projects and the decision to opt for or against Rider I should be permanent. The Utilities submitted that this modification to the Rider I proposal is necessary to prevent potential hardship to the TFOs during periods of capital restraint. The Utilities noted that the AESO would have the ability to refuse or rescind Rider I, however they submitted that this provision would not provide adequate assurance that the opportunity to opt into and out of Rider I would not lead to abuse.[379]

528. In response to the Utilities' suggestion that Rider I be restricted to a one-time only conversion, the AESO submitted that this restriction would likely reduce the utilization of Rider I because it:

- would not allow sufficient time for market participants to assess the implications of Rider I;

374 Exhibit 210.02, UCA argument, page 65, paragraph 320.
375 Exhibit 221.02, UCA reply argument, page 28, paragraph 117.
376 Exhibit 211.01, CCA argument, page 36, paragraph 82.
377 Exhibit 203.01, CCA response to AUC questions, Q7.
378 Exhibit 209.01, Utilities argument, page 68, paragraph 269.
379 Exhibit 209.01, Utilities argument, page 69, paragraphs 274, 276 and 277.

- would not allow market participants who paid construction contributions in the past to utilize Rider I;
- could discourage market participants by requiring them to 'lock into' the new and unfamiliar Rider I approach;
- provides an unnecessary restriction in light of the risk mitigation provided by the financial security requirements incorporated into Rider I; and
- is not necessary to prevent repeated or frequent conversions to or from Rider I, which the AESO can address through it ability to rescind or deny a request for Rider I.[380]

7.2.4 Requirement for TFOs to file adjustments to their approved GTAs

529. On July 15, 2011, the Commission issued additional information requests to all parties. Question 7 asked:

> If the Commission adopts Rider I, should TFOs file adjustments to their approved general tariff applications to reflect any Rider I adjustments?[381]

530. In response to this question, the AESO stated that it would likely take up to two years for Rider I utilization to stabilize. During that transition period, the AESO suggested that TFOs could adjust for Rider I impacts through deferral account reconciliations or other means, including refiling of the TFO's general tariff applications. After the transition period, the AESO submitted that TFOs could file and receive approval for tariff applications in the traditional manner.[382]

531. IPCAA's response echoed the AESO's submission. IPCAA submitted that in the short term, Rider I adjustments for TFOs could be handled through deferral accounts and in the long term, could be forecasted and included in revenue requirements in the TFOs' GTAs.[383]

532. The UCA only stated that Rider I adjustments should not start until appropriate filings have been made and reviewed.[384]

533. As noted above, the CCA stated that there would be the need for a further hearing process to adjust TFO rates. The CCA also recommended that Rider I be required for all DFOs, and this may require adjustments to DFO revenue requirements as well.[385]

534. The Utilities stated that there would be no need for the TFOs to file any changes to their approved revenue requirements as a result of Rider I. Instead, the Utilities submitted that there would need to be a procedural change required to flow through the amount the AESO bills the Rider I customers to the TFOs. The Utilities submitted that, "the costs arising from Rider I would

380 Exhibit 77.01, AESO argument, page 2, paragraph 12.
381 Exhibit 197.01, AUC additional information requests, page 2.
382 Exhibit 200.01, AESO responses to AUC additional information requests, page 3, paragraphs 11-14.
383 Exhibit 202.01, IPCAA responses to AUC additional information requests, page 4.
384 Exhibit 210.02, UCA argument, page 66, paragraph 325.
385 Exhibit 203.01, CCA responses to AUC additional information requests, Q7.

then be directly billed and collected by the AESO from that customer. The AESO would then pass on the billed Rider I amounts to the TFO."[386]

535. In response to the Utilities' submission regarding a procedural change to flow through the Rider I amounts to the TFO, the AESO stated:

> ...there is no need to add the complexity of accounting for specific billed Rider I amounts to transmission facility owners...a transmission facility owner can continue to forecast its rate base net of constructions contributions after implementation of Rider I and the appropriate amounts will be recovered by the AESO from [customers].[387]

7.3 Commission findings

536. In its 2010 GTA application, the AESO proposed Rider I as a solution to the considerable increase in accumulated customer contributions on the balance sheets of the TFOs in recent years. Rider I was supported by a number of industrial customers. The central matter to be determined with Rider I is whether it is in the public interest to permit the conversion of future and existing lump sum contributions from AESO customers into an amortized stream of payments, as a means of alleviating the potential problem of accumulated customer contributions for the TFOs.

537. In the AESO's 2010 GTA proceeding, parties expressed concerns about the AESO's original Rider I proposal. They were concerned that customers other than the Rider I customers might end up bearing the risk of a credit default by a Rider I customer. The Commission is satisfied that the requirement that a Rider I customer post financial security has alleviated most of the concerns about Rider I that parties had expressed. In addition, the Commission finds that the implementation of Rider I may also assist in the credit metrics of the TFOs.[388]

538. Accordingly, the Commission approves Rider I in principle. The Commission directs the AESO to file a specific Rider I tariff application which will give effect to this approval while addressing the following matters.

539. First, the Utilities recommended that the decision by a customer to adopt Rider I should be irrevocable and that Rider I should remain in place for the term agreed to by the customer. The Commission finds that the decision by a customer to adopt Rider I should not be irrevocable. The AESO argued that the up take of Rider I may be limited if the decision to adopt Rider I is irrevocable. The Commission considers that the value of adopting Rider I, as a means of alleviating the accumulated customer contributions on the balance sheets of the TFOs, may be constrained if customers are not allowed to opt out. In addition, the Commission expects that the AESO's ability to deny or rescind Rider I will provide the necessary protection for the TFO's and prevent Rider I customers from abusing the opt out option. The Commission therefore expects that the AESO will include adequate terms and conditions in its Rider I tariff application to prevent abuse of the Rider I opt out option.

540. Second, the Utilities recommended that there should be a one-time limited opt-in period for customers to finance their existing accumulated balance of contributed capital through

386 Exhibit 199.01, Utilities responses to AUC additional information requests, question 7, page 2.
387 Exhibit 216.01, AESO reply argument, pages 2-3, paragraph 18.
388 AltaLink 2009-2010 General Tariff Application, Application No. 1587092, Proceeding ID No. 102, Exhibit 226.01.

Rider I, The Utilities argued that, in the absence of an opt-in period, there is the potential for financial harm to the TFOs during periods of capital restraint, arguably because a TFO may not be able to raise sufficient capital to replace the customer contributions. The AESO argued that an opt-in period may not give customers ample time to assess the implications of Rider I, which may limit the uptake of Rider I. Again, the Commission considers that the value of adopting Rider I, as a means of alleviating the accumulated customer contributions on the balance sheets of the TFOs, may be constrained if there is an opt-in period. Therefore, the Commission does not accept the recommendation by the Utilities regarding the limited one-time offer for Rider I. However, the Commission is also concerned that uncontrolled entries and exits into and out of Rider I could unduly complicate forecasting for utilities. The Commission accepts the argument of the AESO that its ability to deny or rescind Rider I will prevent customers from abusing Rider I. Accordingly, the Commission expects that the AESO will include adequate terms and conditions in its Rider I tariff application to prevent this type of abuse of Rider I by customers to the detriment of the TFOs.

541. Third, the Commission is concerned that the term of the Rider I payments may not match the depreciation lives of the asset financed by way of Rider I. This would, in turn, require that the remaining depreciation expense for the asset financed by Rider I, beyond the Rider I amortization term, be included in the TFO's revenue requirement and be paid for by customers other than the Rider I customer. The Commission is of the view that no one, other than the customer who is adopting Rider I, should be required to pay for the recovery of the cost of any portion of the assets financed by Rider I. The Commission expects that the AESO's Rider I application will resolve this issue.

542. Finally, with respect to any residual concerns regarding other customers bearing the risk of a credit default by a Rider I customer, the Commission reiterates its view that no customer, other than the customer who is adopting Rider I, should be required to pay for the recovery of the cost of any portion of the assets financed by Rider I. With respect to this matter, the Commission agrees with the AESO that the likelihood of a customer becoming insolvent at the same time as the backer of it financial security becomes insolvent is extremely small. However, the Commission finds when a utility asset is stranded and is no longer required to be used for utility service, any outstanding costs related to that asset cannot be recovered from other customers. The Commission relies on the Decision of the Supreme Court of Canada in *Stores Block*[389] for this conclusion. In that decision, the Court states that any assets that are no longer required to be used in utility service are to be removed from rate base.

543. Notwithstanding the submissions of the AESO and other parties referenced in Section 5.5.2 above, that ratepayers rather than utility shareholders are at risk for stranded TFO assets, The Commission is mindful of the conclusions of the Alberta Court of Appeal that assets that are not being used for utility services cannot remain in rate base. In *Carbon*,[390] the Court of Appeal stated at paragraph 29:

> [29] The Act does not contain any provision of presumption that once an asset is part of the rate base, it is forever a part of the rate base regardless of its function. The concept of assets becoming "dedicated to service" and so remaining in the rate base forever is inconsistent with the decision in *Stores Block* (para. 69). Such an approach would fetter the discretion of the Board in dealing with changing circumstances. Previous inclusion in

389 *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4 (*Stores Block*).
390 *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 200 (*Carbon*).

the rate base is not determinative or necessarily important; as the Court observed in *Alberta Power Ltd. v. Alberta (Public Utilities Board)* (1990), 72 Alta. L.R. (2) 129, 102 A.R. 353 (C.A.) at pg. 151: "That was then, this is now."

544. In Decision 2011-176,[391] dealing with Fortis' application for special facilities charge, the Commission quoted *Stores Block* and *Carbon* and came to the conclusion that:

> Given the direction of the courts, it appears to the Commission that if a special facility customer were to abandon the facilities and they were not, within a reasonable period of time, used for other utility customers, those assets would have to be removed from rate base and Fortis shareholders, not remaining utility customers, would bear responsibility for costs.[392]

545. Therefore, the Commission considers that any stranded assets, regardless of the reason for being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service.

7.3.1 Other matters

546. In regards to the request by IPCAA that the DFOs be directed to implement Rider I in a timely fashion for their transmission connected customers, the Commission notes that ATCO Electric already has a rate similar to Rider I in its Rider E,[393] and that FAI has a similar special facilities charge, approved in Decision 2011-176.[394] Accordingly, the Commission expects that the DFOs will determine the level of interest in a Rider I alternative for their respective transmission connected customers and file for a tariff similar to Rider I or modify existing rates, if they deem it necessary.

547. Regarding the proposal by the UCA and the CCA that DFOs be required to take Rider I, the Commission notes the UCA's statement that, in the absence of a management fee, most of its concerns in this area are alleviated. In Section 6, the Commission rejected the management fee proposal of the Utilities, and accordingly, the Commission expects that the concerns of the UCA regarding "double-dipping" are no longer relevant.

548. The UCA and the CCA also argued that the TFOs have a lower equity thickness and consequently a lower weighted average cost of capital than the DFOs and, therefore, customers would be better off if the DFOs were required to take up Rider I. However, the purpose of Rider I is not to place downward pressure on DFO rates, but rather to alleviate the concerns arising from increasing customer contributions for the TFOs. Finally, the Commission has initiated Proceeding ID No. 1162[395] to deal with aspects of the AESO's customer contribution policy. One component of this proceeding will be to examine whether a contribution should be

391 Decision 2011-176, FortisAlberta Inc., Application for Special Facilities Charge, Application No. 1606706, Proceeding ID No. 909, May 2, 2011.

392 Decision 2011-176, paragraph 37.

393 In Exhibit 18.04 of Proceeding ID No. 909 (FortisAlberta Inc. Application for Special Facilities Charge), in response to AUC-004(b), FAI stated: "FortisAlberta understands that ATCO Electric's first Rider E – Facility Charge arrangement was established as part of the ATCO Electric's (Alberta Power at the time) tariffs made effective January 1, 1982."

394 Decision 2011-176: FortisAlberta Inc. Application for Special Facilities Charge, Application No. 1606706, Proceeding ID No. 909, May 2, 2011.

395 Commission-Initiated Application - Electric Transmission Contribution Policy, Application No. 1607193, Proceeding ID No. 1162.

required between two regulated utilities which already have underlying obligations to provide service; examine the potential impact on becoming a direct connect customer if distribution facilities owners do not have to make contributions in the future; and, investigate the means of mitigating any impacts. For these reasons, the Commission will not direct the DFOs take up Rider I at this time.

7.3.2 Implementation for TFOs

549. Finally, with respect to the implementation of Rider I and its effects on the revenue requirements of the TFOs, the Commission notes that all parties except the Utilities argued that there would need to be additional filings with the Commission in order to adjust the revenue requirements of the TFOs. The Utilities suggested that Rider I payments be flowed through directly to the TFOs. Given the uncertainty of the uptake of Rider I, the Commission agrees with the AESO that it would create unnecessary administrative procedures to flow through the Rider I payments directly to the TFOs. The Commission agrees with the AESO that, during the first two years of Rider I implementation, the TFOs can accommodate increases to revenue requirements due to Rider I through a Rider I deferral account. After this period, the TFOs should be able to reasonably forecast their revenue requirement without a Rider I deferral account and can adjust their revenue requirement in their respective GTAs. The Commission therefore approves deferral account treatment for the impacts of Rider I on the TFO revenue requirements for the years 2012 and 2013.

8 Order

550. It is hereby ordered that:

(1) The Generic ROE for 2011 and 2012 is set at 8.75 per cent.

(2) The Generic ROE for 2013 is set at 8.75 per cent on an interim basis.

(3) Equity ratios for the Alberta utilities for 2011 and 2012, and until further changed by the Commission, are as set out in the table below.

(4) Rider I is approved in principle. The Commission directs the AESO to file a separate Rider I tariff application which will give effect to this approval based on the findings in this decision.

(5) The Utilities' request for a management fee as compensation for the provision of service involving assets funded by CIAC is denied.

(6) Utilities are directed to apply to adjust their revenue requirements to reflect the impacts of this decision in due course.

	Last approved (%)	Approved (%)
Electric and Gas Transmission		
ATCO Electric TFO	36	37
AltaLink	36	37
ENMAX TFO	37	37
EPCOR TFO	37	37
RED Deer TFO	37	37
Lethbridge TFO	37	37
TransAlta	36	36
ATCO Pipelines	45	45 for 2011 38 for 2012
Electric and Gas Distribution		
ATCO Electric DISCO	39	39
ENMAX DISCO	41	41
EPCOR DISCO	41	41
ATCO Gas	39	39
FortisAlberta	41	41
AltaGas	43	43

Dated on December 8, 2011.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Panel Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Mark Kolesar
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
Alberta Direct Connect Consumers Association (ADC) R. Secord C. Chekerda
AltaLink Management Ltd. C. Hollar M. G. Massicotte S. McDonald Z. Lazic J. Piotto J. Yeo K. Evans
ATCO Utilities O. Edmondson D. Freedman D. Wilson E. Jansen S. Mah D. Cook C. Warkentin A. Jukov B. McNabb B. Jones B. Yee D. Werstiuk L. Kizuk M. Bayley
AltaGas Utilities Inc. N. J. McKenzie R. Koizumi M. J. Vilbert S. Alexander J. Coleman C. Martin
BP Canada Energy Company (BP) C. G. Worthy G. W. Boone
Canadian Association of Petroleum Producers (CAPP) L. Manning R. Fairbairn N. J. Schultz R. Graham
Consumers' Coalition of Alberta (CCA) J. A. Wachowich A. P. Merani J. A. Jodoin

Name of organization (abbreviation) **counsel or representative**
The City of Calgary (Calgary) D. Evanchuk H. Johnson M. Rowe
Cold Lake Pipeline Ltd. M. Dawson S. Zubcic
EPCOR Distribution & Transmission Inc. (EDTI) J. Liteplo P. Wong
EPCOR Energy Alberta Inc. (EEAI) J. Liteplo P. Wong
ENMAX Power Corporation (EPC) D. Wood J. Neri D. Emes G. Weismiller K. Hildebrandt J. Schlauch J. Worsick
FortisAlberta Inc. T. Dalgleish, Q.C. I. Lorimer M. Stroh J. Sullivan J. Walsh
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Industrial Power Consumers Association of Alberta (IPCAA) M. Forster R. Mikkelsen S. Fulton V. Bellissimo R. Cowburn
Alberta Electric System Operator (AESO) J. Cusano J. Martin
City of Lethbridge M. Turner D. Hudson O. Lenz

Name of organization (abbreviation) counsel or representative
Nexen Marketing R. Stevens T. Eastman
City of Red Deer P. A. Smith M. Turner L. Gan
Shell Canada Energy D. Burnie
TransCanada Energy Ltd. V. Kostesky R. Stevens
Terasen Gas Inc. I. Bevacqua
TransCanada Keystone Pipeline Gp Ltd. V. Kostesky R. Stevens
TransAlta Corporation B. Smith K. Perley L. Zaitsoff P. Serafini
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. J. Parker

The Alberta Utilities Commission
Commission Panel M. A. Yahya, Panel Chair B. Lyttle, Commission Member M. Kolesar, Commission Member
Commission Staff V. Slawinski (Commission counsel) S. Russell (Commission counsel) S. Allen J. Olsen O. Vasetsky J. Thygesen K. Schultz S. Karim

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
ATCO Utilities L. Smith, QC K. Illsey	Panel 1 – ROE and Capital Structure K. McShane A. Engen Panel 2 – ATCO Pipelines Panel K. McShane E. Jansen Panel 3 – Management Fee K. McShane
AltaLink Management Ltd. H. Williamson, QC	
FortisAlberta Inc. T. Dalgleish, QC	
AltaGas Utilities Inc. N. McKenzie	
EPCOR Distribution & Transmission Inc. J. Liteplo	
ENMAX Power Corporation D. Wood	
Alberta Electric System Operator (AESO) J. Cusano	J. Martin G. Sharma
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Office of the Utilities Consumer Advocate (UCA) N. Parker R. McCreary	G. Roberts L. Kryzanowski W. Marcus
Canadian Association of Petroleum Producers (CAPP) L. Manning	L. Booth
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn S. Fulton D. Levson E. de Palezieux

The Alberta Utilities Commission

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M. Kolesar, Commission Member

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S. Russell (Commission counsel)
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J. Olsen
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