PETER C.P. THOMPSON, Q.C.
T 613.787.3528
pthompson@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St, Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
F 613.787.3558 (IP)
blg.com

Borden Ladner Gervais

By electronic filing

November 16, 2012

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

Enbridge Gas Distribution Inc. ("EGD") 2013 Rates - CME Compendium re: Cost of Capital	
Board File No.:	**EB-2011-0354**
Our File No.:	**339583-000132**

Please find enclosed a Compendium of materials to which we expect to refer during our cross-examination of the Cost of Capital witnesses.

This Compendium is submitted on behalf of Canadian Manufacturers & Exporters ("CME").

We will bring a few hard copies of the material to the hearing. We will not have sufficient hard copies for all parties and encourage those who are interested in the material to make their own copies from the materials transmitted electronically.

Yours very truly,

Peter C. P. Thompson, Q.C.

PCT\slc
enclosure
c. Robert Bourke (EGD)
Intervenors EB-2011-0354
Paul Clipsham (CME)

OTT01: 5371464: v1

EB-2011-0354

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

COMPENDIUM OF CANADIAN MANUFACTURERS & EXPORTERS ("CME") RE: COST OF CAPITAL

November 16, 2012

Peter C.P. Thompson, Q.C.
Borden Ladner Gervais LLP
100 Queen Street
Suite 1100
Ottawa, ON K1P 1J9

Counsel for CME

	Tab #
EB-2011-0210, Union Gas Limited, Decision and Order dated October 25, 2012, cover page and pp.42-51	1
EB-2011-0354, Exhibit I, Issue E1, Schedule 20.3	2
EB-2011-0354, Exhibit I, Issue E1, Schedule 21.2	3
EB-2011-0210, Exhibit J.E-2-14-1	4
EB-2011-0210, Exhibit A3, Tab 7	5
EB-2011-0354, Exhibit I, Issue E2, Schedule 4.1	6
EB-2011-0354, Exhibit I, Issue E2, Schedule 5.1 plus Attachment	7
EB-2011-0354, Exhibit I, Issue E2, Schedule 7.2	8
EB-2011-0354, Exhibit I, Issue E2, Schedule 14.2	9
EB-2011-0354, Exhibit I, Issue E2, Schedule 20.1	10
EB-2011-0354, Exhibit I, Issue E2, Schedule 21.1	11
EB-2011-0354, Exhibit I, Issue E2, Schedule 21.3, Attachment 2	12
EB-2011-0354, Exhibit I, Issue E2, Schedule 21.5 plus Attachment	13
EB-2011-0354, Exhibit I, Issue F2, Schedule 4.1 plus Attachments	14
EB-2011-0354, Exhibit I, Issue F2, Schedule 5.1 plus Attachment	15
EB-2011-0354, EGDI Interrogatory	16
Curriculum Vitae of Professor Laurence Booth	17
Letter from counsel for CME to counsel for EGD, dated November 15, 2012	18

OTT01: 5370561: v1

TAB 1

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2011-0210

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

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND ORDER

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

The results of the review are to be subject to a stakeholder information process and then be submitted in conjunction with Union's next rates proceeding (cost of service or incentive regulation regime).

COST OF CAPITAL

Union's investment in rate base is financed by a combination of short-term and long-term debt, preferred shares and common equity. The current Board approved capital structure is based on a 36% common equity component. The remaining 64% is financed by a mix of short-term debt, long-term debt and preferred shares.

Union has proposed a capital structure which includes a common equity ratio of 40% for 2013 as compared to the 36% currently included in rates. The 36% equity ratio was set as a result of a Settlement Agreement in the 2007 Cost of Service Proceeding (EB-2005-0520).

Union has proposed a long-term debt ratio of 60.17% and a debt rate of 6.53%. The short-term debt ratio is -2.92% with a rate of 1.31%. The average embedded cost of preferred share capital for 2013 is 3.05%. This is a decrease from the 2007 Board approved cost of 4.74%.

Common Equity Ratio

Most intervenors and Board staff submitted that Union's proposal to raise the common equity ratio from 36% to 40% should be rejected. IGUA did not take any position on this issue.

In support of its proposal, Union retained two experts: Mr. Steven M. Fetter and Dr. Vander Weide. In response, intervenors presented the expert evidence of Dr. Lawrence D. Booth.

Intervenors and Board staff cited the Report of the Board on Cost of Capital for Ontario's Regulated Utilities[17] that provided guidelines with respect to a gas utility's capital structure. The report on page 50 states:

[17] Report of the Board on Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084),pp. 49, 51.

> For electricity transmitters, generators and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.

Intervenors and Board staff submitted that Union had made no attempt to comply with the guideline in requesting a change in the equity thickness and Union's evidence indicated that it had not analyzed its financial and business risk as part of this proceeding. Board staff and intervenors further noted that Union's argument was that its current equity structure is not commensurate with its risk. However, Union agreed that its business or financial risk had not changed materially since 2006. In fact, Union witnesses confirmed several times during the oral hearing that there had been no material increase to its business or financial risk.[18] Union agreed in reply that its risk profile had not changed but it noted that in the 2007 rates case, Dr. Carpenter and the Brattle Group stated that Union's business risk warranted an equity ratio between 40 and 56%, depending on the allowed rate of return.[19] Union therefore believed that an equity ratio of 40% was appropriate based on its current risk profile.

Mr. Fetter was of the opinion that an equity thickness of 40%-42% would improve Union Gas' financial profile benefitting its customers through Union's enhanced ability to attract capital from investors when needed and upon reasonable terms. Mr. Fetter, in his report, also indicated that equity ratios of utilities were rarely set below 40% in the United States. Mr. Fetter further noted that a review of other Canadian gas utilities showed that the deemed equity ratios were in the range of 39% to 43%. In its Argument-in-Chief, Union submitted that it had to compete for capital with other utilities across the United States and Canada and a 36% equity ratio puts Union at a disadvantage.[20]

In reply, Union submitted that none of the intervenors had challenged Union's position that other comparable utilities had higher equity ratios than 36% and that Union was lower relative to its peers. Union further submitted that no party challenged the comparability of Union to ATCO Gas or Terasen. Union disputed intervenors' argument that comparability has no value and noted that Dr. Booth, the expert consultant of the

[18] Oral Hearing Transcripts, EB-2011-0210, Volume 4 at p. 128 and Volume 5 at pp. 15 and 31.
[19] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 105.
[20] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p. 53.

intervenors, in his testimony confirmed that the regulator should give weight to the deemed equity ratios of comparable utilities.[21]

CCC submitted that the Board consistent with its own policy must examine the individual circumstances of Union and in particular, the business and financial risk faced by Union to determine whether a change in capital structure is required. CCC further submitted that the use of comparators may supplement, but cannot replace that analysis. CCC also disputed Mr. Fetter's opinion that a higher equity ratio would allow Union to withstand future unforeseen events. CCC argued that Mr. Fetter's opinion was hypothetical.

Intervenors and Board staff submitted that Union had provided no evidence that it has not been able to compete for capital on favourable terms with other utilities. Intervenors and Board staff submitted that throughout the IRM period which coincided with a severe global financial crisis, Union had maintained a high credit rating. Union has been able to attract capital on reasonable terms under its current capital structure. Intervenors and Board staff referred to an interrogatory response[22] where Union confirmed that an equity ratio of 40% would not lead to a higher credit rating or a lower cost of debt. This view was also stated in the Standard and Poor's report which notes that Union would not get a higher rating than Spectra, its parent. In Reply, Union submitted that DBRS in its report noted that Union had requested a 40% deemed equity ratio. Union submitted that in that report DBRS expected Union to manage its balance sheet in line with the new regulatory capital structure and maintain greater financial flexibility commensurate with the current rating category. Union argued that this meant that Union would fit more appropriately with the current rating if it had a 40% common equity.[23]

Dr. Booth in his testimony expressed the view that one major aspect of risk was whether a utility was able to earn its allowed return on equity. Dr. Booth noted that since 2000, Union's average over-earning was about 2%. Intervenors and Board staff in their submission noted that Union had over-earned by approximately $278.7 million from 2007 to 2012. Intervenors and Board staff submitted that Union had provided no evidence to demonstrate a change in its risk profile. In reply, Union submitted that there

---

[21] Oral Hearing Transcripts, EB-2011-0210, Volume 6 at p. 61.
[22] Exhibit J.E-1-1-2.
[23] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 102.

is a surplus of supply east of Union's Dawn to Parkway system and that posed a significant risk to Union. Union noted that there was further risk of turnback and this was reflected in lower revenues on Dawn to Kirkwall and M12.[24]

BOMA, in its submission, submitted that Union's interest coverage ratio was 2.74 which was higher than the 2% minimum interest coverage ratio set out in Union's trust indenture. This was higher than the ratios in 2008, 2009 and 2010 when it was 2.4%and 2.24% in 2007. However, the interest coverage ratio was lower than the threshold when the unregulated business was excluded from the calculation. BOMA further submitted that with respect to the interest coverage ratio, the common practice was to look at the entire company and not just the regulated portion of the business.[25] Union, in reply, disagreed with BOMA and submitted that this view was at odds with the general focus of intervenors that pursue to ensure that there is no cross-subsidy of the unregulated business by the regulated business. Union submitted that the intervenors wanted the Board to agree that it was appropriate to cross-subsidize the regulated business in order to meet the interest coverage ratio.

CCC in its argument cited the Ontario Court of Appeal in its decision (Toronto Hydro-Electric System Limited v. Ontario Energy Board, 2010) where the court stated that regulated utilities must balance the needs of shareholders and ratepayers. CCC submitted that if the proposed change in capital structure is approved, Union's shareholders will benefit by approximately $17 million while there would be no corresponding benefit within the test year to Union's ratepayers. CCC submitted that the Board should conclude that Union had not balanced the interests of its ratepayers and shareholders and accordingly disallow the change in the common equity ratio.

LPMA submitted that if the Board does approve Union's proposal or approves an equity ratio greater than the current 36%, then in that case, the Board would have to deal with how to treat preferred shares in the deemed capital structure. LPMA submitted that according to USGAAP, Union's preference shares were classified as equity by their auditors. LPMA submitted that there was no reason for the Board to deviate from the USGAAP treatment. SEC disagreed with LPMA and submitted that when the Board reviewed Union's capital structure in 2004, it did not consider preference shares to be equity and the Board should therefore refrain from doing so in this case. SEC submitted

[24] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 107.
[25] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 88.

that the preference shares should be treated as long-term debt. Union agreed with SEC and noted that the Board had never considered Union's preference shares in any assessment of Union's common equity ratio. In addition, Union noted that they were not even considered relevant by Dr. Booth in his analysis.

SEC, in its submission, agreed with Union that the Board's Report on Cost of Capital is a guideline. However, it noted that the Board had thoroughly reviewed the business risk of Union in 2004 and unless there was a change in the business risk, there was no need for a utility to come before the Board with a different proposal. SEC submitted that Union was merely rearguing the 2004 case and there was no new evidence to show a change in risk.

SEC further submitted that Union had not articulated any benefits to ratepayers such as better access to market or lower borrowing costs, which Union already enjoys. In reply, Union submitted that the expectation that a higher equity ratio must be accompanied by lower borrowing costs or a ratings upgrade is unrealistic. Union therefore submitted that the Board should reject the submissions of intervenors.

Unlike other intervenors, LPMA and SEC submitted that Union's common equity ratio should be reduced from 36% to 35% consistent with what the Board had determined when it last reviewed the business risk and equity thickness of the company in 2004.

Cost of Debt

None of the intervenors raised any issues with the rates for short-term and long-term debt or preferred shares. LPMA however made a submission on the mix of short-term and long-term debt.

LPMA submitted that Union's proposal of a long-term debt ratio of 60.17% and a short-term debt ratio of -2.92% meant that ratepayers were being asked to pay a long-term debt rate on $108.5 million of borrowings and receive a credit at the short-term debt rate. LPMA submitted that this was not appropriate and was an indication that Union was over capitalized for rate base purposes.

LPMA noted that Union attributed the negative short-term debt to items outside of rate base that the utility has to invest in, such as construction work-in-progress and the contribution in excess of expenses for pension.

Union's average short-term borrowing for 2013 is predicted by LPMA to be $136 million[26] which represents approximately 3.66% of Union's rate base.

LPMA and SEC submitted that Union has more long-term debt than needed to finance rate base. This is under the scenario of a 36% and a 40% common equity ratio. At the same time, these scenarios have not included any short-term debt according to LPMA.

LPMA and SEC submitted that the Board should direct Union to include $136 million in short-term debt in the cost of capital calculation. Both parties further submitted that the balancing figure would be the long-term debt component. LPMA considered this to be an appropriate approach since in its view it was obvious that some of the long-term debt is being used to finance items outside of rate base.

In reply, Union noted that its cash position varied significantly due to the seasonal nature of its business. It further stated that long-term debt changes do not occur quickly and that the cash position would slowly return to short-term debt as the long-term debt level adjusted through maturities and reduced issues. Union submitted that issuing debt in small amounts was administratively burdensome and lumpy. Union indicated that it obtains long-term financing when prudent and tries to take advantage of favourable market conditions.

Union further submitted that having a negative short-term balance was not a new issue and the Board had addressed this before in the RP-2003-0063 proceeding. In the RP-2003-0063 Decision with Reasons dated March 18, 2004, the Board, on page112, determined that Union was in compliance with its deemed capital structure even though its long-term debt had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance.

Union emphasized that in the RP-2003-0063 Decision, the Board had used the word "marginal" to describe the level of excess in the long-term debt component. The actual

[26] Oral Hearing Transcripts, EB-2011-0210,Volume 5 at p. 40.

unfunded short-term debt was approximately $130 million in 2004 which is higher than the current unfunded short-term debt component of $115 million. Union submitted that the Board should reach a similar conclusion in this proceeding and not make any adjustments to the short-term or long-term debt component.

Board Findings

<u>Deemed Common Equity Thickness</u>

The Board finds that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio that was in place over the 2007 to 2012 period, inclusively.

The 2009 Cost of Capital Policy of the Board at page 43 sets out that for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risks.

Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.

Union put forth two arguments to support its application for a 40% deemed common equity ratio. The first is that the current deemed common equity ratio of 36% is too low and has never appropriately reflected its business and financial risk. Second, that the deemed common equity ratio should be increased solely on the basis of comparability; i.e., because other Canadian utilities now have higher deemed common equity ratios, the Board should also approve a higher deemed common equity ratio for Union.

The Board will address each of these two arguments in turn.

The Board does not accept the proposition that the deemed common equity thickness of 35% as determined by the Board in 2004 and subsequently increased to 36% as a result of a Settlement Agreement was incorrect and that it did not adequately reflect Union's financial and business risk profile. Union has filed no evidence to support this position that the deemed equity ratio was not correct and the Board therefore gives this argument little or no weight.

The Fair Return Standard ("FRS") requires that a fair or reasonable return on capital should:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

Union's second argument focuses on the first part of the comparable investment standard – that the return on invested capital must be comparable. However, Union's argument fails to address the second part of the comparable investment standard, that being the issue of "enterprises of like risk". Union would have the Board increase (and potentially reduce) its deemed common equity ratio in lock-step with the decisions of other regulators, without an analysis of whether the utilities to which it is compared are enterprises of like risk.

The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union asserted were comparable. The Board notes, however, that neither Union nor the intervenors filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete.

The Board is aware that since the 2008 financial crisis, the deemed common equity ratios of certain Canadian rate regulated entities have been increased. However, no evidence was filed in this proceeding that set out the risks that resulted in findings supporting higher deemed common equity for these utilities and no evidence was filed that demonstrates Union faces similar risks.

Union reiterated throughout the proceeding that its business and/or financial risks have not changed since 2006.

Accordingly, there is no reasonable basis for the Board to increase Union's deemed common equity ratio above the 36% level presently reflected in rates.

The Board does not agree with the submission of SEC that a higher deemed equity ratio must be supported by benefits to ratepayers. The Board's obligation to determine the quantum of common equity (at issue in this proceeding) and the cost of that equity (subject to the Settlement Agreement) is governed by the FRS, which is a non-optional, legal standard.

The Board also does not agree with the submission of CCC that the Board must balance the interests of ratepayers and shareholders in determining the deemed common equity ratio. Consistent with the jurisprudence discussed in the 2009 Cost of Capital Policy, the Board remains of the view that it is not in the determination of the cost of capital that investor and consumer interests are balanced. This balance is achieved in the setting of rates.

Finally, the Board is of the view that there is no evidentiary basis to support a reduction in deemed common equity from the existing 36% to 35%.

Cost of Debt and Preferred Shares

The Board approves the cost of short-term, long-term debt, and preferred shares as per Appendix B, Schedule 3 of the Settlement Agreement. The Board notes that no issues were raised by intervenors or Board staff regarding the appropriateness of these costs during the proceeding.

Debt and Preferred Share Capitalization

The Board approves the amount of long-term debt, short-term debt, and preferred share equity as set out by Union in Exhibit J5.4, page 2, lines 7 through 12, which reflects the Settlement Agreement relating to this proceeding and deemed common equity of 36%.

The Board's findings on the amount of short-term and long-term debt are consistent with previous decisions of the Board and are consistent with Union's evidence that items outside of rate base are funded by short-term debt.

The Board has not undertaken a comprehensive review of whether it is appropriate for a gas utility to have preferred shares in its capital structure. The Board is generally aware that preferred shares are often referred to as "mezzanine capital", having characteristics of both debt and equity. There was no assessment of the characteristics of Union's issued and outstanding preferred shares in this proceeding. Similarly, there was no assessment of whether Union's issued and outstanding preferred shares should be considered to be common equity or debt for the purpose of determining Union's capital structure in order to set utility rates.

The Board will thus continue its current practice of approving the amount and cost of Union's preferred shares as a separate part of total utility capitalization. The Board notes, however, that the presence of preferred shares has the effect of reducing the amount of total debt capitalization in Union's capital structure.

COST ALLOCATION

General Cost Allocation Issues

Union provided a summary description of the methodology used to complete the cost allocation study, which supports the 2013 rate proposals. Union submitted that subject to the removal of the unregulated storage operations and certain proposals in Exhibit G1, Tab 1 (which are discussed below), the cost allocation study is consistent with the studies that were approved by the Board and used in the past, including in EB-2005-0520.

Union noted that the objective of the cost allocation study is to allocate the utility test year cost of service to customer rate classes for the purpose of acting as a guide to the rate design process. To allocate costs, the test year cost of service is analyzed to determine the appropriate functionalization and classification of costs. Union noted that the allocation of costs to individual rate classes is based upon these determinations.[27]

Union stated that the cost allocation study consists of three steps. These steps are:

Functionalization of costs to utility service functions: The first step of the cost allocation process is to associate asset and operating costs with the various utility service functions. There are four functions generally accepted as necessary to obtain and move gas to market: purchase and production of gas, storage, transmission, and distribution.

Classification of costs to cost incurrence (demand, commodity, customer): The second step categorizes functionalized asset and operating costs into classifications according to cost incurrence. The three main classifications are demand-related, commodity-related, and customer-related. Demand-related costs, also known as capacity-related costs are costs that vary with peak day usage of the system. Commodity-related costs are costs that are typically variable in nature and vary with the

[27] Exhibit G3, Tab 1, Schedule 1 at p. 1 (Updated).

TAB 2

VECC INTERROGATORY #3

INTERROGATORY

E- Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: Exhibit E1 Tab 1 Schedule 1

a) Please update Table 2 to reflect actual data for 2011.

b) Provide a version of Table 4 that assumes no change in Equity Thickness.

RESPONSE

a) The following table has been updated to reflect the 2011 Actual/Historical cost of capital. The common equity cost rate utilized is the 2011 Board Approved ROE of 7.94%, plus the 100 basis points (1%) allowed before earnings sharing is triggered, as per the terms of the Company's 2008 through 2012 incentive regulation agreement. This information is also reflected in the updated exhibits at Exhibit E5, Tab 1, Schedule 1, and Exhibit F5, Tab 1, Schedule 1.

Cost of Capital Summary

Line No.		2011 Historical				
		Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	2,319.6	58.62%	6.02%	3.53%	139.6
2.	Short-term debt	112.9	2.85%	1.61%	0.05%	1.8
3.	Preferred shares	100.0	2.53%	2.40%	0.06%	2.4
4.	Common equity	1,424.5	36.00%	8.94%	3.22%	127.4
5.	Total	3,957.0	100.00%		6.85%	271.2

Witnesses: K. Culbert
M. Lister
D. Yaworsky

b) The following update of Table 4 takes into account the updated results of Impact Statement Number 1 (Exhibit M1, Tab 1, Schedule 5), but assumes common equity thickness remains at 36%, and includes the capital structure impacts for CIS. Please note that the table below assumes the change in the equity ratio (from 42%) is accounted for with short term debt. If the Board did not approve the Company's request for a 42% equity ratio, EGD would investigate financing alternatives, which may include use of long term debt which is different from that presented in the table below.

Cost of Capital Summary (Weighted)

Line No.		2013 Test Year Including CIS				
		Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	2,357.9	56.49%	5.89%	3.33%	138.9
2.	Short-term debt	213.5	5.11%	3.70%	0.19%	7.9
3.	Preferred shares	100.0	2.40%	4.16%	0.10%	4.2
4.	Common equity	1,502.7	36.00%	9.02%	3.25%	135.5
5.	Total	4,174.1	100.00%		6.87%	286.5

Update

As requested in Technical Conference Undertaking JT2.16, the cost of capital summary in part b) above has been updated to incorporate the long-term debt assumptions, identified in Updated Exhibit I, Issue E2, Schedule 7.3, that would result if the Board determined that the deemed equity ratio be maintained at 36%. In addition, the short-term debt and preference share cost rates have been updated utilizing current forecasts, as identified in Exhibit I, Issue E1, Schedules 7.1 and 7.2.

Witnesses: K. Culbert
M. Lister
D. Yaworsky

Cost of Capital Summary (Weighted)

Line No.		2013 Test Year Including CIS				
		Principal ($millions)	Component %	Cost Rate %	Return %	Return ($millions)
1.	Long-term debt	2,507.0	60.06%	5.79%	3.48%	145.2
2.	Short-term debt	64.4	1.54%	2.00%	0.03%	1.3
3.	Preferred shares	100.0	2.40%	3.20%	0.08%	3.2
4.	Common equity	1,502.7	36.00%	9.02%	3.25%	135.5
5.	Total	4,174.1	100.00%		6.84%	285.2

Witnesses: K. Culbert
M. Lister
D. Yaworsky

TAB 3

CME, CCC, SEC, VECC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E1: Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

Reference: EGDI Evidence E1, Tab 2, Schedule 1,Testimony of D. Yaworski.

Commercial paper and long term debt cost

a) Please provide an all-in cost analysis of the commercial paper program by including forecast "interest" costs as well as standby and other bank fees.

b) Please indicate whether the typical electricity distributor allowed a 40% common equity ratio by the Board has access to the CP market, and if not please explain why not.

c) Please confirm that EGDI maintains the ability to issue first mortgage bonds, as confirmed in previous hearings, and that these bonds are not covered by a 2X interest coverage ratio new issue restriction.

d) For each of the years 2007 to 2011 inclusive, please provide EGDI's actual earnings and its interest coverage ratio.

e) Please provide EGDI's interest coverage ratio for 2013 using a 36% equity ratio and the Board's Formula ROE.

f) Please list all of EGDI's financings since January 1, 2007 and provide the amount of time that elapsed between the date information circulars were distributed to the public soliciting support for the investments and the date and time when the investments described therein were fully subscribed.

g) How do the rates that EGDI paid for each of its financings in the period 2007 to date inclusive compare with the cost of debt derived using the formula the Board approved in its December 11, 2009 Cost of Capital Report?

Witnesses: K. Culbert
M. Lister
D. Yaworski

RESPONSE

a) The following summarizes the updated commercial paper forecasted rates for 2012 and 2013:

	2012	2013
Forecasted Commercial Paper Rate	1.50%	2.00%

EGDI maintains a $700 million committed credit facility that backstops the commercial paper program. The Company is charged an annual $50,000 administration fee, 0.22% standby fee on undrawn balances and 0.06% fee to extend the maturity date each year. The administration, extension and standby fees are estimated at $2 million annually and amortized over a two year period. In addition, the Company is charged approximately $200,000 per year to maintain the rating coverage in support of the commercial paper credit ratings.

b) EGD is not in a position to comment on the financial arrangements or market accessibility of other companies.

c) Confirmed.

d) Please see the table below:

	2007	2008	2009	2010	2011
Earnings (After ESM)	140.1	134.9	140.4	140.3	138.5
Interest Coverage	2.5	2.4	2.5	2.5	2.5

e) The interest coverage ratio for 2013 using a 36% equity ratio would be 2.3, assuming that the 2013 deficiency is recovered and that the difference in equity ratio (from 42%) were financed entirely with short term debt. To the extent that the deficiency were not recovered or that long term debt was used to finance some portion of the difference in equity ratios, then the interest coverage could be significantly lower.

Witnesses: K. Culbert
M. Lister
D. Yaworski

f) The following outlines all the outstanding public term debt financings:

	ENBRIDGE GAS DISTRIBUTION Maturity Date	Years to Maturity	Notional Outstanding	Coupon Rate
MTN	Dec-04-2017	5.96	200,000,000	5.16%
DEB	Dec-02-2024	12.96	85,000,000	9.85%
MTN	Oct-02-2025	13.79	20,000,000	8.85%
MTN	Oct-29-2026	14.87	100,000,000	7.60%
MTN	Nov-03-2027	15.88	100,000,000	6.65%
MTN	May-19-2028	16.42	100,000,000	6.10%
MTN	Jul-05-2023	11.55	100,000,000	6.05%
MTN	Nov-12-2032	20.91	150,000,000	6.90%
MTN	Dec-16-2033	22.00	150,000,000	6.16%
MTN	Sep-24-2014	2.76	200,000,000	5.16%
MTN	Feb-25-2036	24.20	300,000,000	5.21%
MTN	Jan-29-2014	2.11	200,000,000	5.57%
MTN	Dec-17-2021	10.00	175,000,000	4.77%
MTN	Nov-23-2020	8.93	200,000,000	4.04%
MTN	Nov-22-2050	38.95	300,000,000	4.95%
			2,380,000,000	CAD

All public term debt issuances are offered and subscribed to following the governing security law requirements and Canadian debt capital market precedents.

g) The Board's policy for deriving the cost of debt for the electric utilities states:

"The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield."[1]

The table below compares the cost of debt derived using the Board's formula for the electric utilities and EGD's cost of Debt Financing.

[1] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, Ontario Energy Board, Case # EB-2009-0084, December 11, 2009, p. 59.

Witnesses: K. Culbert
M. Lister
D. Yaworski

	EGD Cost of Debt Financing	Deemed Cost of Debt for Electric Utilities
2007	5.429	5.369
2008	6.035	5.839
2009	5.865	6.176
2010	5.124	5.665
2011	4.708	5.483

Witnesses: K. Culbert
M. Lister
D. Yaworski

TAB 4

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit A3, Tab 7
Exhibit E1, Tab 1
Exhibit E2

In connection with this evidence, please provide the following additional information:

a) For the most recent financings listed in Exhibit A3, Tab 7, what was the amount of time that elapsed between the date the information circulars were distributed to the public and the investments described therein were fully subscribed?
b) How do the rates that Union paid for each of its financings for 2010 and 2011 described in Exhibit A3, Tab 7 compare with the cost of debt derived using the Board's formula?
c) What financings were made by Ontario Power Generation Inc. ("OPG"), Hydro One Networks Inc. ("HONI") and Enbridge Gas Distribution Inc. ("EGD") in the same time frame, and at what rates?
d) How do the interest rates for Financings made by OPG, HONI, and EGD over the past 5-years compare to the rates paid by Union?
e) Has there been any change in Union's stand-alone credit ratings over the past 5-years?

Response:

a) These issuances were launched in the morning and subscribed by that afternoon.

b) Union's debt was issued at a lower rate than the Board's formula.

	Effective Rate	Board Formula	Difference
2010	5.27%	5.64%	(0.37%)
2011	4.93%	5.48%	(0.55%)

c) Union does not have this information.

d) Union does not have this information.

e) Yes, there has been one change in Union's credit ratings over the past 5 years. On January 2, 2007, Standard & Poor's increased the Company's credit ratings on debentures and preferred shares to BBB+ and P-2 (low) respectively.

TAB 5

UNION GAS LIMITED

Prospectuses, Information Circulars for Most Recent Financing

- 4.88% $300,000,000 MTN Debentures, issued June 21, 2011, due June 21, 2041
- 5.20% $250,000,000 MTN Debentures, issued July 23, 2010, due July 23, 2040
- 6.05% $300,000,000 MTN Debentures, issued September 2, 2008, due September 2, 2038
- 5.35% $200,000,000 MTN Debentures, issued April 28, 2008, due April 27, 2018
- 4.85% $125,000,000 MTN Debentures, issued November 23, 2006, due April 25, 2022
- 5.46% $165,000,000 MTN Debentures, issued September 11, 2006, due September 11, 2036

The previous Medium-Term Note Disclosures were issued on September 21, 2005. Information on this was filed at EB-2005-0520, Exhibit A3, Tab 7.

TAB 6

CME INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E1, Tab 1, Schedule 1

The Board conducted a full assessment of EGD's equity ratio in the EB-2006-0034 proceeding which was decided by Reasons for Decision dated July 5, 2007. The Board then determined that a 36% equity ratio was appropriate for EGD.

In the Board's Cost of Capital Report dated December 11, 2009, the Board described its policy and the guiding principles that it will apply in re-assessing the appropriateness of the capital structures for electricity transmitters, generators and gas utilities as follows:

> *"For electricity transmitters, generators and gas utilities, deemed capital structure is determined on a case by case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk."* (emphasis added)

Is EGD attempting, in this case, to have the Board reverse this stated policy?

RESPONSE

EGD believes that its request for an increase in equity thickness is consistent with the Board's stated policy and the Fair Return Standard. The base capital structure has been stable over a long period of time, increasing by only 1% over a period of nearly 20 years. EGD believes there has been a change in the company's business risk, measured on both an absolute basis since 1993, and on a relative basis compared to North American peers and Ontario's electric utilities.

As stated in its evidence, EGD believes that the current equity ratio of 36% is not reflective of changes in business risk over time. That is, in 1993, the equity ratio was

Witnesses: K. Culbert
R. Fischer
M. Lister

set at 35%. Since that time there have been fundamental changes that have increased business risk for gas distribution utilities. EGD believes that the 1% increase in equity ratio from 2007 is neither fully reflective of the increased business risk since 1993, nor reflective of the Board's Fair Return Standard.

Further, EGD's position is that the current equity ratio of 36% is significantly below that of North American peer utilities with comparable business risk and Ontario electric utilities which exhibit lower business risk. Concentric Energy Advisor's analysis shows that Ontario's gas utilities' capital structures have fallen out of line with like-risk peers, and they conclude that the allowed equity ratio for EGD is insufficient and does not meet the standard of fairness. In addition, EGD submits that gas distribution is relatively riskier than electric distribution. Both the Alberta Utilities Commission and a former OEB expert have taken this position (see Exhibit E2, Tab 1, Schedule 2, p.p. 9-11). EGD's position is that the Fair Return Standard requires that EGD's equity ratio should be at least as high as that approved for Ontario electric utilities, on a comparative business risk basis.

Witnesses: K. Culbert
R. Fischer
M. Lister

TAB 7

CCC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E1/T1/S1

Please provide all materials provided to EGD's Board of Directors and/or to Enbridge Inc. seeking approval to seek an increase in the allowed equity level from 36% to 42%.

RESPONSE

The attached presentation materials were presented to EGD's Executive Management Team in July, 2011, recommending approval to seek an increase in the allowed equity level. Enbridge Inc. was briefed on the basis of this recommendation. A determination to apply for an increase from 36% to 42% was not made by EGD until approximately November, 2011, once Concentric Energy Advisors had completed their analysis and recommendation.

Witnesses: K. Culbert
R. Fischer
M. Lister

Equity Thickness

Mike Lister, Ralph Fischer

ENBRIDGE

Equity Thickness

ENBRIDGE

- 2006 Backgrounder
- Equity Thickness Impacts
- North American Industry
- Concentric opinions & thoughts
- Thoughts, insights from Treasury

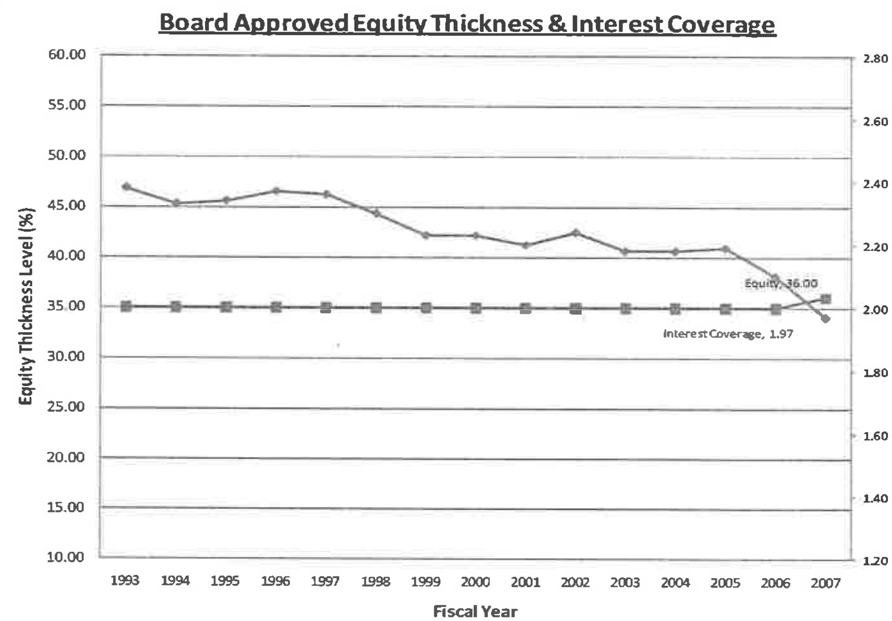
2006 Backgrounder

ENBRIDGE

- ♦ **Main position centred on two themes:**
  - → **Increased Risk Profile since 1990 (when 35% was established)**
  - → **Forecast difficulty in meeting coverage ratios**

Higher Risk Environment (since 1990):

- **Natural gas prices & volatility**
- **Increase conservation efforts and impacts**
- **DSM impacts**
- **Appliance uses and standards**
- **Trend towards multiples, away from single, detached dwellings**
- **Different housing price dynamics**



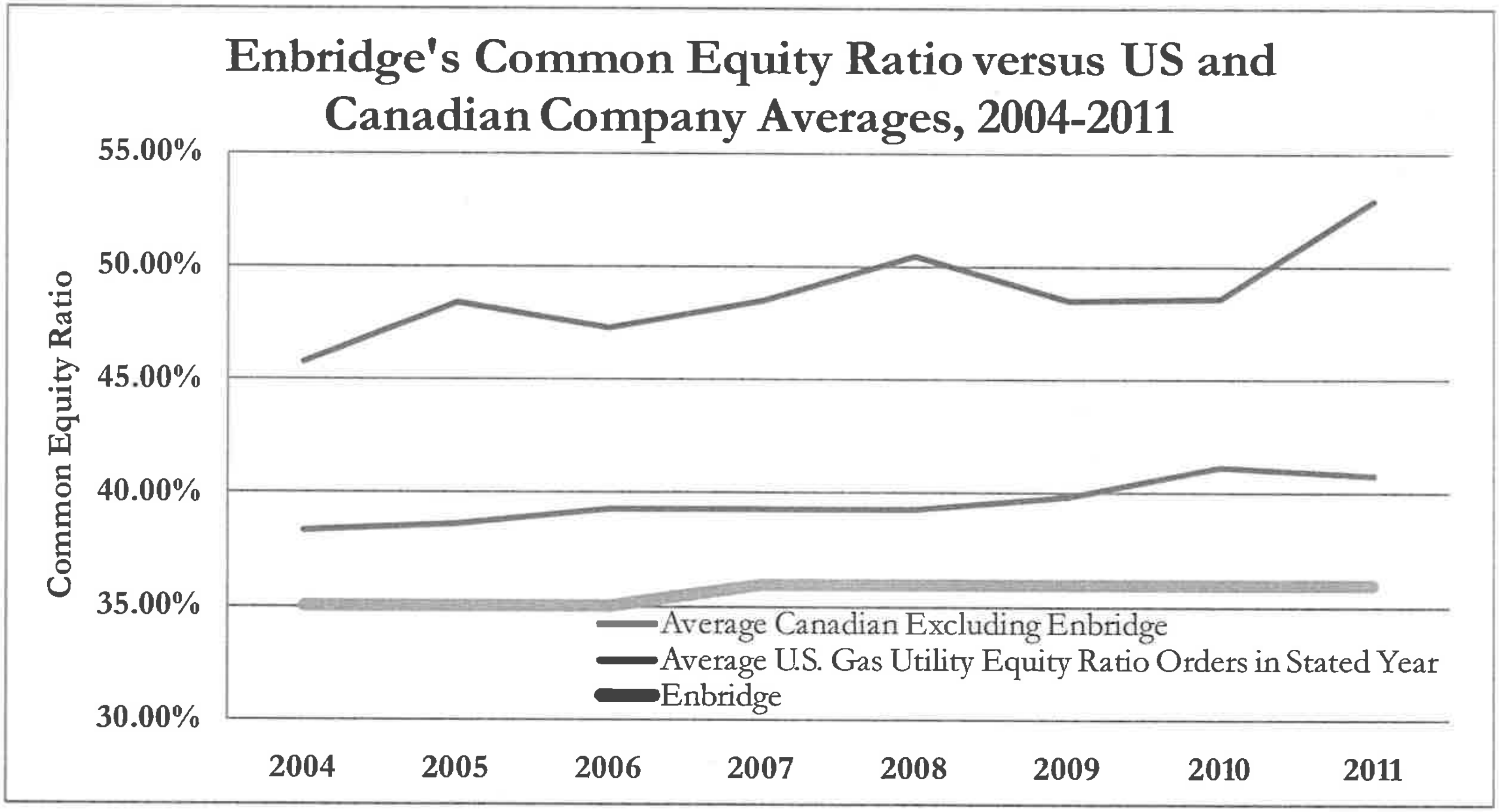
Equity Thickness Impacts

ENBRIDGE

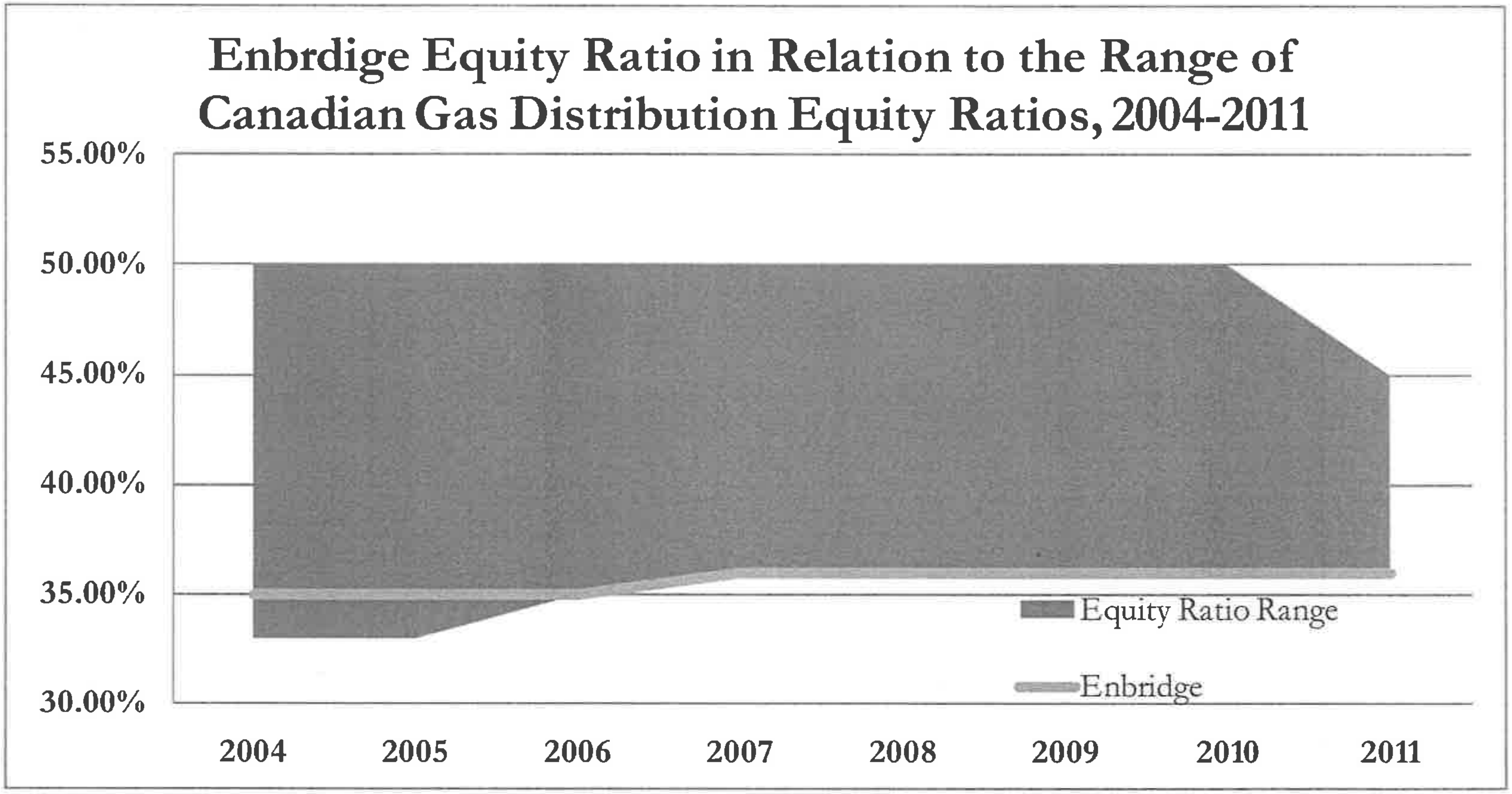
Rate Base	ROE	Equity Thickness	Annual After-Tax Earnings Impact
$4,000 M	10 %	36 %	$144 M
$4,000 M	10 %	40 %	$160 M
		Difference	$16 M
		Difference per 1%	$4 M

- → **Union Gas will ask for Equity Thickness of 40% in 2013**
- → **Ontario Electrics currently at 40% Equity Thickness**
- → **Alberta and TQM decisions say gas distribution is riskier than electrics; 2009 case, EGD argued we were riskier than electrics**

Canada, U.S.A., Enbridge



Enbridge: Bottom of the Pack



Pros/Cons of More Equity (Concentric opinion)

ENBRIDGE

Pros

- Improves earnings and financial ratios, and strengthens credit ratings
- Potentially lowers cost of debt
- Provides greater financial flexibility for major projects, cushion for unanticipated events, or distribution up to Enbridge Inc.
- Brings Enbridge into conformity with other Canadian LDCs
- Better aligns Board allowed ROE with equity ratio
- Timing – currently lower gas prices provides rate headroom, and financial crisis reinforced value of liquidity

Cons

- Increases rates
- Expectation that Enbridge Inc. will infuse the equity – is this the best use of equity capital?
- Might see Board/stakeholder resistance to move from current ROE of 8.39% to generic rate of 9.58%, along with more equity
- Potentially weakens settlement "gives" by stakeholders on other issues (e.g., IR terms)

Thoughts, Insights from Treasury

ENBRIDGE

- Increased equity ratio could deliver improved debt ratings and reduced debt/issuance costs
- However, debt rates are at historic lows and are likely to increase by at least 100 basis points over the next four years
- With an equity ratio increase, best case scenario is neutral impact to future debt rates, though higher debt rates are more likely
- To achieve the higher equity %, EI would inject equity and leave distribution policy unchanged

Filed: 2012-08-03, EB-2011-0345, Exhibit I , Issue E2, Schedule 5.1, Attachement 1

Recommendation

ENBRIDGE

- Prepare a case to present to the OEB for a higher equity thickness (likely 40%)
  - ➢ Draft & finalize a scope and project budget cost for Concentric to represent EGD
  - ➢ Use Company and Consultant resources to build case around several main themes:
    - ⇨ Relative increase in risk environment since the early 1990s
    - ⇨ Risk of downgrade vs. cost of equity thickness
    - ⇨ Comparison of EGD to Canadian and US Gas LDCs
    - ⇨ Application and maintenance of the Fair Return Standard
  - ➢ Prepare Checkpoint presentation for the EMT ~early September
  - ➢ Have draft evidence prepared ~late September

Questions / Feedback

ENBRIDGE

TAB 8

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

E – Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: Exhibit E2, Tab 1, Schedule 2

a) When is the last time the OEB approved the common equity ratio for EGD?

b) Please provide the percentage of total distribution revenue (excluding gas costs) that was recovered through each of monthly fixed charges, firm demand charges and variable volumetric rates in 1993 and 2011. If data for 1993 is not available, please provide the percentages for each year in 2007 through 2011.

c) Does use of the AUTUVA account eliminate the risk associated with residential average use consumption for all drivers but weather? Please explain any other risks, other than weather, that remains with the AUTUVA.

d) Does the AUTUVA account apply solely to Rate 1 customers? If not, what other rate classes does it apply to?

e) Has EGD considered the use of a true up account for industrial demand? If no, why not? If yes, please explain why EGD has not proposed such an account in this proceeding.

f) With respect to the System Size and Complexity, is it EGD's position that because it is bigger it has more risk and therefore requires a higher common equity ratio? If yes, does this mean that if EGD were split into 2 smaller companies, both would have less risk, and therefore a need for a lower common equity ratio?

g) Are the figures noted in paragraph 21 in real or nominal dollars? If they are in nominal dollars, what has been the cumulative increase in inflation between 1993 and 2013?

Witnesses: R. Fischer
M. Lister
D. Yaworski

RESPONSE

a) Please see the response to VECC Interrogatory 1, filed at Exhibit I, Issue E2, Schedule 20.1.

b) In 1993, the forecast amount of distribution revenue recovered from fixed charges was 18%. For 2011, the forecast amount of fixed charge recovery was 52%.

c) The Average Use True-Up Variance Account ("AUTUVA") was the result of a negotiated settlement as part of the Incentive Regulation Framework. Its purpose is to protect both small volume consumers and the Company from any variances from forecast volumes for a given test year. The following table highlights the AUTUVA account true-up revenue balances over the 2008-2011 (proposed) years:

($ Millions)				
	2008	2009	2010	2011*
Rate 1	1.48	2.53	4.59	4.86*
Rate 6	(4.13)	3.09	(6.74)	(7.81)*
Total	(2.65)	5.63	(2.15)	(2.95)*

*Pending Board Approval

As can be seen the typical balances have been small, and on an aggregate basis have protected consumers for forecasts that would have resulted in otherwise higher charges.

As explained in the Company's evidence, since 2007, the AUTUVA has helped mitigate the impact of uncertainty around declining average use. The AUTUVA ensures that revenues are not impacted by variances from the forecast average use decline. If the actual average use decline is less than forecast, then customers are credited for the difference through the disposition of the variance account. Alternatively, if the actual average use decline is greater than forecast, then customers are debited for the difference.

Thus, the AUTUVA minimizes the intra-year revenue impact associated with the uncertainty of actual residential average use declines compared to the forecast; however, it does not address the longer-term implications that result from a trend of declining average use.

Other risks besides weather that can impact the business include cost variability that could arise as a result of ageing infrastructure or safety issues, training, the price of materials, the movement of interest rates or utility credit spreads, the costs of labour, the costs related to insurance, litigation, or bad debts, the ability to generate other revenues as forecast, the economic impacts on volumetric demand generally, or on industrial uses in particular. There are risks associated with an ageing workforce, with technical, safety or compliance standards as well as operational risks associated with a massive inventory of underground facilities of varying vintage, including pipes fittings, valves, or pressure stations. There are risks associated with third party damages, employee health and safety, or environmental and physical risks, and the associated costs, associated with ruptured or leaking infrastructure. There is also the risk that other outside influences may have on consumption patterns such as weather, the demand for gas across North America, the availability and access to supply, storage spreads, the price of fuel oil, or other energy alternatives. There are also risks associated with the advancement of other forms of energy technologies, or with regulatory or legislative impacts on either the revenue or the cost side. This list of risks is not necessarily exhaustive and may include others as well.

Aside from the list of absolute risks, the Fair Return Standard states that the cost of capital should represent an amount that is commensurate with investment of like risk. On a relative basis, it is the Company's position that the gas distribution business is riskier than the electric distribution business. Both the gas and electric utilities in Ontario use the same ROE formula to derive ROE, and yet the Ontario electric utilities have equity ratios that are higher than the gas distribution equity ratios. Furthermore, the Company's equity ratio is not consistent with investments of like risk based on a carefully constructed US peer group analysis, or with other utilities across Canada.

d) No, the AUTUVA account does not apply solely to Rate 1 customers. The AUTUVA also applies to Rate 6 customers.

e) No, EGD has not considered a true up account for industrial demand.

The AUTUVA is designed to remove any variance from forecast average use impacts related to small volume customers. This is facilitated by the ability to accurately forecast small volume average uses. Small volume average uses can be forecast with a high degree of accuracy because of the homogenous customer characteristics of rate 1 and rate 6 customers, respectively, and the relatively easy to identify forecast driver variables (i.e. gas prices, heating stock vintage, economic activity, etc.). Conversely, industrial volumes by their nature are much more difficult to predict. There are many more rate classes that are comprised of a heterogeneous group of customers ranging from retail outlets, to large scale manufacturing with natural gas used in the manufacturing process. Also, the drivers of demand for these customers might not be as consistent as that which exists for the small volume classes. That is, demand in specific industries may be affected by industry specific events or circumstances.

Therefore, the ability to forecast average industrial volumes is much lower than that for small volumes, and the practicality of administering an AUTUVA related to industrial load would be very difficult. There is a very high probability that such an account would result in very volatile and unpredictable amounts for true up, which would result in greater rate volatility, and greater rate shock. This, in turn, would upset customers. EGD would also be concerned if hard or soft caps were introduced to alleviate any negative rate shock, exposing the Company to additional risk, with no apparent upside.

Alternatively, the rate impacts associated with the Rate 1 / Rate 6 AUTUVA account have been relatively small, and in favour of EGD's ratepayers.

f) Please see the response to CME, CCC, SEC, VECC Interrogatory 3, filed at Exhibit I, Issue E2, Schedule 21.3 for a response as to the Company's position with respect to business risk and system size.

g) The figures noted in paragraph 21 are in nominal dollars. Please see the response to CME, CCC, SEC, VECC Interrogatory 3, filed at Exhibit I, Issue E2, Schedule 21.3 for a representation of the same figures in paragraph stated in 2012 dollars.

Witnesses: R. Fischer
M. Lister
D. Yaworski

TAB 9

SEC INTERROGATORY #2

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Ref: E2/1/2, p. 2

Please provide details of all changes to business risks that the Applicant and/or its experts Concentric believe have arisen a) in the period 1993 to 2007, and b) in the period 2007 to date.

RESPONSE

EGD and Concentric believe that business risks have increased since 1993 to 2011. EGD and Concentric do not believe it is necessary to differentiate risk growth between the two time periods 1993 to 2007 and 2007 to date. Rather, what is necessary is to determine whether the deemed equity ratio is properly situated as a result of changes in business risk over the entire time period. The changes to business risk can be found in the evidence at Exhibit E2, Tab 1, Schedule 2, and Exhibit E2, Tab 2, Schedule 1.

Witnesses: R. Fischer
M. Lister

TAB 10

VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: Exhibit E2 Tab 1 Schedule 2

Preamble: The Board's draft (cost of Capital) Guidelines assume that the base capital structure will remain relatively constant over time and that a full re assessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk (page 50).

a) Please provide an extract and reference to the Settlement and/or the Decision approving the current common equity ratio for EGD.

b) Please provide the percentage of total distribution revenue from fixed charges, and firm demand charges at the time of the increase in equity thickness and in-2013.

c) Explain why the following do not serve to reduce EGDIs Business Risk relative to:
   a. the period prior to their implementation and
   b. relative to other Utilities

      i. AUTUVA
      ii. LRAM/LRAMVA

d) How many of Canadian and US utilities in the sample have

      i) General Service declining use protection (AUTVA)
      ii) LRAM protection and
      iii) Are/are not exposed to weather risk

Please provide a chart that shows these attributes on a comparable basis.

e) Confirm that EGDI (and EI) is also compensated for Conservation efforts via the SSM and provide the Annual amounts 2007-2011 earned by the shareholder.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

f) Contrast the SSM amounts earned by EGDI to those of Hydro One Distribution over the same period.

RESPONSE

a) The current common equity ratio for EGD was established for the 2007 test year (EB-2006-0034), and was the result of a Decision. The following is an extract from that decision. For the complete reference, please see the Decision with Reasons – Phase 1, July 2007, p.p. 62-66.

> "In consideration of all of the above, and on balance, the Board finds an increase in the common equity thickness from 35% to 36% to be reasonable."

The Board further stated:

> "While Union's current 36% common equity was the result of a negotiated settlement, Enbridge's proposal for a 38% common equity level is materially higher than Union's, which is not consistent with the relative business risk profile of the two utilities."

EGD notes that while Union may have been satisfied with the negotiated trade-off that resulted in the currently 36% equity ratio, that Union is no longer satisfied that a 36% equity ratio is appropriate for its business conditions, as evidenced by their request for an increase in equity thickness to 40% for the 2013 test year.

b) Equity thickness increased from 35% to 36% in 2007. In 2007, the amount of distribution revenue recovered from fixed charges was 33%. For 2013, the amount of fixed charge recovery is forecast to be 51%.

c) Please refer to Appendix B of the Concentric Report, pages B-2 through B-6 for a discussion of business and operating risks and how they may be addressed in the regulatory framework. Specifically, EGDI's AUTUVA and LRAM serve to reduce the emerging risks of declining gas use per customer and that from conservation, but do

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

not protect the company from fluctuations due to weather, and accordingly do not warrant the full credit for risk mitigation enjoyed by many of the other proxy companies. The LRAM was introduced as a mechanism to remove the potential incentive barrier in the pursuit of conservation and to provide for a true up for intra-year variances, so that both the Company and ratepayers are not negatively impacted from variances to the forecast. Though these mechanisms have undoubtedly reduced the volumetric risk of EGDI compared to before their implementation, such mechanisms have become the norm for a gas utility and are more likely to raise capital costs by their absence than to reduce capital costs by their presence. The AUTUVA and LRAM are specifically discussed on page B-4.

d) Please refer to part (c) above. Figure 10, on page B-3 of Appendix B, compares revenue stabilization mechanisms employed by EGDI (LRAM and AUTUVA) to those employed by the proxy group. As Figure 10 shows, all of the other members of the comparable group employ the same or better protection against volumetric risk due to weather, declining use or conservation as does EGDI. Any company with a solid ball in the "Revenue Stabilization" category would be deemed to satisfy the three listed attributes, i.e. are immune to volumetric risk, whether it be due to conservation, declining use, or weather. A partial ball would indicate that the company remains exposed to volumetric risk, either due to weather or due to declining use. Page B-5 discusses to what extent volumetric risk is mitigated by the comparable group. For example, volumetric risk may be mitigated by straight-fixed variable rate design; a conservation mechanism used in concert with a weather normalization mechanism, or a full decoupling mechanism. A brief description of what sort of rate stabilization mechanisms each comparable company employs is included on page B-5.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

e) EGDI earns a financial incentive (SSM) to recognize performance against set annual Demand Side Management targets. The 2007 – 2011 SSM amounts were as follows:

2007 – $8.25 M
2008 – $5.80 M
2009 – $5.36 M
2010 – $4.16 M
2011* – $6.69 M

*Per Audit report as at July 11, 2012 and subject to clearance of accounts and Ontario Energy Board approval.

f) EGD is not able to produce the Hydro One SSM results.

Witnesses: J. Coyne
K. Culbert
R. Fischer
J. Lieberman
M. Lister

TAB 11

CME, CCC, SEC, VECC INTERROGATORY #1

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 1, Schedule 1 Updated, Testimony of R Fischer et al

Return on Equity, pages 1 to 3

a) Please provide a table showing EGDI's allowed ROE, actual ROE on a weather adjusted basis, actual unadjusted ROE, and actual unadjusted ROE before sharing since 1990, that is, prior to the 1993 and 2006 business risk assessments.
b) Please provide for each year since 1997 and the use of a formula ROE, the ROE broken out into the risk free rate component and the earned risk premium component (residual).
c) For each year since 1997 please provide a table with the average amount of common equity used for rate making purposes, and the amount of net income with the net income broken out into the risk free rate and risk premium component as identified in b) above.

RESPONSE

a) Please see the table provided on the following page:

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

Fiscal Year		Allowed ROE %	Normalized Actual ROE Before Sharing %	Actual ROE Before Sharing %	Normalized Actual ROE After Sharing %	Actual ROE After Sharing %
1990		13.250%	13.600%	13.570%	(a)	(a)
1991		13.125%	13.290%	9.400%	"	"
1992		13.125%	13.400%	13.290%	"	"
1993		12.300%	14.430%	15.260%	"	"
1994		11.600%	12.490%	14.690%	"	"
1995		11.650%	12.660%	10.710%	"	"
1996		11.875%	13.140%	15.000%	"	"
1997		11.500%	13.000%	13.170%	"	"
1998		10.300%	11.970%	8.310%	"	"
1999		9.510%	10.771%	7.943%	"	"
2000		9.730%	10.829%	8.229%	"	"
2001		9.540%	10.029%	10.800%	"	"
2002		9.660%	11.805%	8.982%	"	"
2003		9.690%	9.743%	13.140%	"	"
2004		9.690%	10.828%	12.342%	10.660%	12.165%
2005		9.570%	10.343%	10.343%	(a)	(a)
2006		8.740%	10.343%	7.200%	"	"
2007		8.390%	10.722%	11.639%	"	"
2008		8.660%	10.208%	11.867%	9.936%	11.586%
2009		8.310%	11.203%	12.361%	10.261%	11.422%
2010		8.370%	11.103%	10.248%	10.241%	9.386%
2011	(b)	7.940%	10.378%	10.433%	9.661%	9.719%

Note : (a) There were no earnings sharing amounts in these years, so ROE results are the same as in the previous columns.

(b) 2011 results are pending Board approval in EB-2012-0055.

b) The information requested is provided in tabular form on the following page. This information can also be seen graphically in response to CME, CCC, SEC, VECC Interrogatory # 2, filed at Exhibit I, Tab E2, Schedule 21.2, part b).

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

Fiscal Year	Board Approved ROE	Long Bond Forecast Embedded in ROE Formula Result	Implied Risk Premium in ROE Formula Result
	%	%	%
1998	10.30%	6.78%	3.52%
1999	9.51%	5.73%	3.78%
2000	9.73%	6.02%	3.71%
2001	9.54%	5.77%	3.77%
2002	9.66%	5.93%	3.73%
2003	9.69%	5.97%	3.72%
2004	9.69%	5.97%	3.72%
2005	9.57%	5.81%	3.76%
2006	8.74%	4.70%	4.04%
2007	8.39%	4.24%	4.15%
2008	8.66%	4.61%	4.05%
2009	8.31%	4.14%	4.17%
2010	8.37%	4.23%	4.14%
2011	7.94%	3.65%	4.29%

c) EGD does not feel that a response to this part of the interrogatory would be helpful to the Board, as it appears to imply that some portion of the Company's earnings could be labeled as 'risk-free'. EGD feels it is inappropriate to suggest that part of the company's net income can be labeled 'risk-free' or 'risk-premium' net income. A risk premium model is used to estimate or to proxy a fair return on equity for a regulated entity (ex. ante) because there is no way of directly observing what a fair return should be. Notionally labeling part of the net income as risk-free would be akin to suggesting that the Company could simply take its capital and earn a risk free rate of return. The risk for a gas distribution business relates to operations, safety, reliability, cost variability, regulatory risk, weather, interest rates, demand, supply, etc. There is no aspect of the business that is 'risk-free'.

Witnesses: K. Culbert
R. Fischer
M. Lister
S. Murray

TAB 12

UTILITY EQUITY THICKNESS REQUIREMENT

Overview

1. The purpose of this evidence is to clearly identify the need for a higher equity thickness in the Ontario Energy Board (the "Board") approved capital structure for the utility. This need results from changes in Enbridge Gas Distribution's current business risk environment and financial risk position. The evidence will show that the utility's business risks have increased since the last time these risks were assessed in EBRO 479 for the 1993 test year. Most importantly, the increased business risk has occurred at the same time as a dramatic decline in the Company's financial strength resulting in: 1) a challenge to the Company's ability to raise term debt when required; and 2) a real risk of a further downgrade in the Company's credit rating.

2. If uncorrected, Enbridge Gas Distribution will not meet its new term debt issue financial covenant based on 2006 forecast results and may be unable to issue new term debt in 2007 based on the current utility allowed equity thickness and return on equity. Furthermore, if the utility's financial integrity is not restored, the Company's credit rating may be downgraded which would cause a number of debt investors to sell their Enbridge Gas Distribution debt holdings in order to avoid breaching the debt holders' investment criteria.

3. Consequently, Enbridge Gas Distribution is requesting an increase in the utility's common equity thickness from 35.0% to 38.0% effective January 1, 2007 to restore the financial integrity of the utility to the level required to enable the Company to sustain access to long term capital on reasonable terms and prudently manage its business risks.

Witnesses: B. Boyle
J. Denomy

4. The Company has provided a "Glossary of Terms" on the final pages of this schedule to facilitate the understanding of the financial terminology.

Equity Thickness History

5. The issue of an appropriate level of equity thickness for Enbridge Gas Distribution was last addressed in front of the Board in the EBRO 479 rate case which set rates for the 1993 test year. The Company argued that it should be allowed to employ an actual equity ratio of 35.51%. The Board's findings in this instance were as follows:

> The Board notes that the immediate impact of the company's proposal to employ an actual equity ratio would be an increase in the equity component. The Board finds that such a thickening is not justified by the evidence. The Board, therefore, rejects the proposed use of the company's 35.51 percent equity as the equity component for ratemaking purposes in the fiscal year. The board deems a common equity ratio of 35 percent to be appropriate for Consumers Gas in fiscal 1993.[1]

6. Table 1 shows the history of Enbridge Gas Distribution's deemed equity thickness from 1985. Despite a changing business environment, there have been no changes to the Company's deemed capital structure since the 1987 test year.

[1]Ontario Energy Board, "EBRO 479 Decision With Reasons", March 3, 1993, pg 91.

TABLE 1

Col. 1 Year	Col. 2 Deemed Equity Thickness (%)	Col. 3 Year	Col. 4 Deemed Equity Thickness (%)
1985	37.00	1996	35.00
1986	36.00	1997	35.00
1987	35.00	1998	35.00
1988	35.00	1999	35.00
1989	35.00	2000	35.00
1990	35.00	2001	35.00
1991	35.00	2002	35.00
1992	35.00	2003	35.00
1993	35.00	2004	35.00
1994	35.00	2005	35.00
1995	35.00	2006	35.00

7. There have been material changes to the business environment in which the Company operates since 1993 the last time business risk and an appropriate level of equity thickness was assessed. The Company believes that its business risks have increased significantly and that an increase in the equity component of its deemed capital structure from 35% to 38% is appropriate given the business and financial risks currently faced by the Company. Under the cost of service regulatory framework, equitable rate setting relies on the Company's ability to accurately forecast the revenues generated from distribution and the costs incurred in providing distribution services. Increased volatility in the underlying drivers of gas consumption puts the Company at risk of greater forecasting error. Given the Company's current financial risk position, any large deviations between actual and forecast revenues or costs will have an impact on the Company's earnings and

possibly its credit rating and access to capital. Paragraphs 11 to 27 discuss the business risks faced by the Company.

Business Risks

8. Business risk is affected by volatility in a firm's operating earnings due to the risk inherent in a firm's underlying operations. These risks are a result of uncertainty in demand for a firm's products, and the firm's ability to ensure products are priced to recover the costs incurred in the production or provision of services. In the absence of any debt financing in a firm's capital structure only the shareholder faces the business risk. Once debt financing is introduced into a firm's capital structure the firm becomes leveraged and must be able to meet the fixed charges and debt covenants required by lenders. Leverage introduces the concept of financial risk into the risk profile faced by equity holders.

9. Capital structure, the amount of debt and equity used to finance a firm, is a function of the amount of business risk faced by the firm. Volatility in earnings is one of the drivers of higher business risk. Higher levels of business risk will generally require a higher level of equity in a firm's capital structure such that fixed charges and debt covenants stemming from financial leverage are adequately covered. Conversely, lower levels of business risk will support a lower level of equity financing as the risk of not meeting fixed charge obligations and covenants is less.

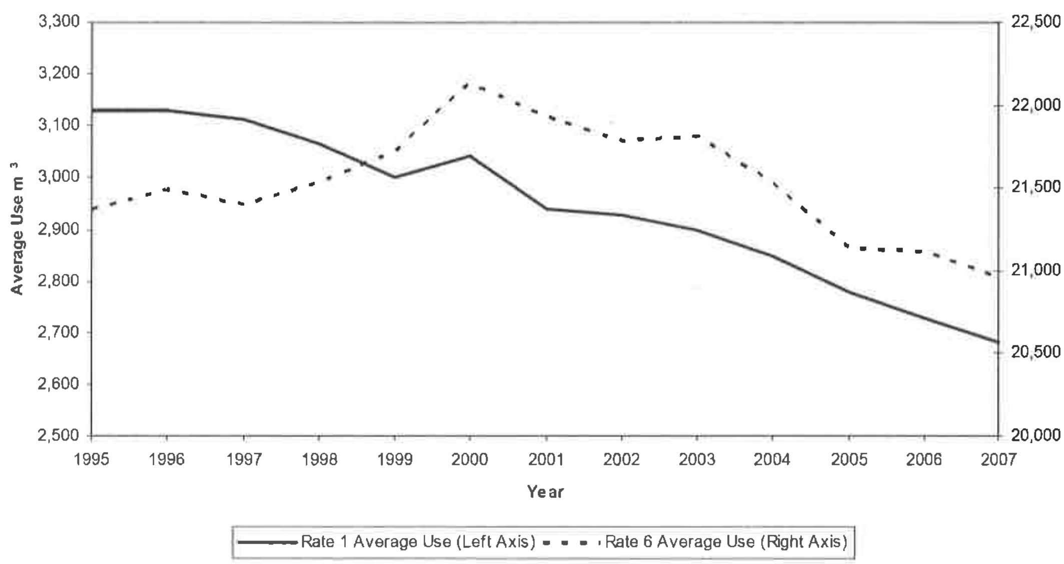
10. For a gas distribution utility, business risk ultimately relates to the utility's ability to recover its investment in its assets or rate base, while at the same time achieving its allowed return on equity and maintaining a sufficient level of protection to meet fixed charges and debt covenants. Significant factors that affect the level of business risk faced by a gas distribution utility are the price of natural gas and alternative energy

forms, the dynamics of its customer base, the regulatory environment, forecast risks and the general economic environment in which the utility conducts business.

a. Volumetric Risks

11. General service average use has been declining since the early 1990's. Figure 5 shows average use for Rate 1 and Rate 6 normalized to 2007 budget degree days. On average, Rate 1 average use has declined by 1.2% per year since 1995 and Rate 6 average use has declined by 0.1% per year since 1995. Since 2001, Rate 1 average use has declined by 1.8% on average and Rate 6 average use has declined by 0.9% on average.

Figure 5



12. The decline in average use is a result of a combination of factors such as higher and more volatile gas prices, self imposed and government imposed conservation in light of higher energy costs and environmental concerns, and changes in the

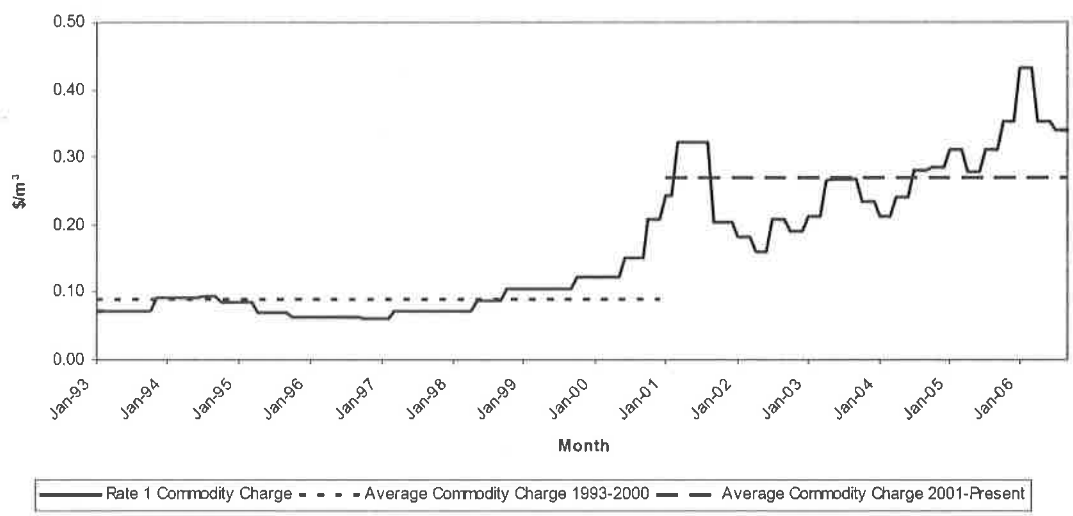
Witnesses: B. Boyle
J. Denomy

customer and housing/building stock. Increased volatility in the underlying drivers of gas consumption puts the Company at risk of greater forecasting error for gas consumption. Given the Company's current financial risk position, any large deviations between actual and forecast volumes will have an impact on the Company's earnings and possibly its credit rating and access to capital.

b. Natural Gas Prices Increases and Volatility

13. From 1993 until 2000, natural gas commodity prices remained relatively stable and showed little volatility. Since then, natural gas commodity prices have become more volatile and increased dramatically. Figure 1[2] shows the system sales gas supply charge per cubic meter for Rate 1 (residential) customers.

Figure 1



[2] The averages shown in Figure 1 and calculated in Table 2 and the standard deviations calculated in Table 3 are calculated using monthly data from January 1993 to December 2000 and January 2001 to September 2006 for the 1993-2000 and 2001-Present periods respectively. Calculations are inclusive of September 2006 system sales gas commodity charges as these are the most recent actual commodity charges known at the time this evidence was written.

Witnesses: B. Boyle
J. Denomy

14. It is clear from Figure 1 that natural gas commodity costs have increased dramatically since 2000. Table 2 shows the average system sales gas supply charge from 1993 to 2000 and 2001 to the present. The average system sales gas supply charge has increased 198% over the two time periods.

TABLE 2

Col. 1	Col. 2
Average 1993-2000 ($/m^3)	0.090
Average 2001-Present ($/m^3)	0.269
% Change	198.29%

15. In addition to an upward trend in price, commodity price volatility has increased dramatically since 1993 as well. Table 3 shows the standard deviation[3], a measure of volatility, of the Rate 1 system sales gas supply charge from 1993 to 2000 and 2001 to the present. The standard deviation of the system sales gas supply charge has increased 116% over the two time periods.

TABLE 3

Col. 1	Col. 2
Standard Deviation 1993-2000 ($/m^3)	0.031
Standard Deviation 2001-Present ($/m^3)	0.066
% Change	115.67%

[3] Standard deviation is calculated as: $StDev = \sqrt{\frac{\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2}{n-1}}$.

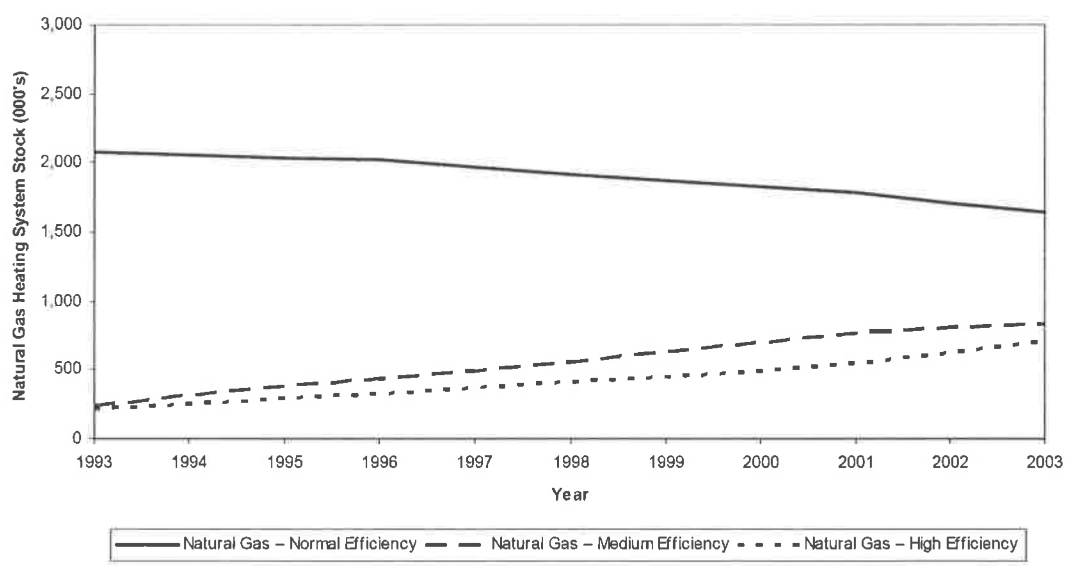
Witnesses: B. Boyle
J. Denomy

16. Increasing energy costs and energy price volatility ultimately cause customers to conserve and reduce energy consumption. Periods of increasing prices and price volatility result in a large range of price changes which can occur over short periods of time. The end result is self induced conservation efforts on the part of utility customers which ultimately result in reduced natural gas consumption and therefore earnings.

c. <u>Natural Gas Appliance Use</u>

17. Natural gas remains the primary source of energy for space heating for the Company's residential customer sector. However, the incidence of medium and high-efficiency natural gas furnace usage has been increasing. Figure 2 shows the natural gas heating system stock by efficiency type for Ontario.

Figure 2



Witnesses: B. Boyle
J. Denomy

18. In 1993 medium and high efficiency furnaces made up 9% of the overall natural gas furnace market in Ontario. In 2003 medium and high efficiency furnaces comprised 48% of the natural gas furnace market in Ontario. As building code regulations on new home energy efficiency become more stringent, the trend towards medium and high efficiency furnace installation will continue. Replacement of older less efficient appliances with new, more efficient appliances will reduce gas consumption for existing customers. Furthermore, builder specifications for non-gas appliances represent a risk to the extent that new customers may be influenced to purchase non-gas appliances for their homes due to builder specifications.

19. These factors are contributors to a declining average use per customer.

d. <u>Customer Dynamics</u>

20. The housing market in Ontario has experienced dramatic growth over the past few years. There has been a trend toward the construction of multiple, rather than single detached homes. Semi-detached and town-homes are typically smaller than single family dwellings. Lower square footage reduces the space requiring heating resulting in lower consumed volumes for new customers. Figure 3 shows single versus multiple housing starts within the Greater Toronto Area ("GTA").

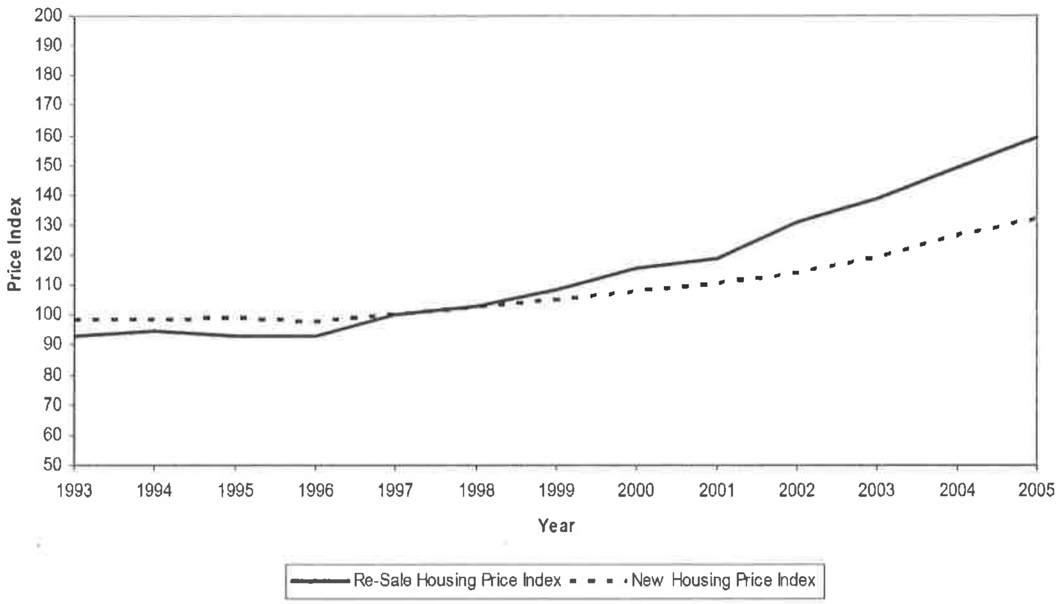
Figure 3

21. In addition to an increase in multiple housing starts, housing prices in general have increased dramatically across the Enbridge Gas Distribution franchise area. Figure 4 shows a price index[4] for new and re-sale homes in the GTA.

4 1997=100

Witnesses: B. Boyle
J. Denomy

Figure 4



22. Higher prices for new and pre-owned homes make the purchase of new semi-detached or town-homes relatively more affordable. A preference for smaller, more affordable multiple homes will likely cause further growth in this housing type and a related reduction in average gas consumption.

e. Regulatory and Legislative Environment

23. As outlined above, business risk results from uncertainty in the Company's ability to sell its product and in its ability to price its product to recover costs. A regulated entity's ability to forecast and recover costs is strongly influenced by its regulatory environment. The regulatory environment has seen a significant increase in the number of intervenors and proceedings over the past few years. Enbridge Gas Distribution is of the opinion that these factors in conjunction with forthcoming

proceedings increase uncertainty with respect to forecasting costs and recovering them.

24. Ontario gas utilities are in the midst of several proceedings under the Natural Gas forum umbrella which are expected to re-define the regulatory environment and create uncertainty, at least until their resolution. These include the Natural Gas Electricity Interface Review proceeding that contemplates regulatory changes to the natural gas storage environment in Ontario, the addition of a significant new natural gas market through gas fired generation and unbundling of services. Proceedings to establish an Incentive Regulation Framework and various other processes to review cost allocation issues, long term contracting and QRAM methodology are other components of the Natural Gas Forum. Other processes that create uncertainty with respect to the operating environment include GDAR. Recent decisions with respect to allowing the first physical bypass of the natural gas distribution system in Ontario (Greenfields Energy Centre ("GEC") RP-2005-0022, EB-2005-0441, EB-2005-0442, EB-2005-0443, EB-2005-0473) and treatment of the proceeds from sale of investor owned assets (cushion gas) add to uncertainty.

25. Taken together, the proceedings described above affect every facet of the Company's operating environment. The GEC Decision sets a new precedent with respect to the interpretation of franchise rights. GDAR and unbundling of rates and services affect market segments where the regulated entity participates with competitive entities. These proceedings impose costs on the regulated entity to facilitate competition, while at the same time subjecting the utility to uncertainty about cost recovery through the subsequent exercise of choice by customers. Uncertainty with respect to cost recovery of upstream gas costs to serve currently

bundled customers is particularly important given that these costs are a large multiple of the Company's earnings. Finally, the Company welcomes the opportunity to participate in a process leading to lighter handed incentive regulation, which could reduce regulatory risk by reducing the number of proceedings and interventions. On the other hand, a new framework that does not explicitly recognize declining average use, the need to incur significant capital expenditures, coupled with the other industry changes described above could increase regulatory risk.

26. The Company faces further uncertainty due to the recent decision by the Canadian Accounting Standards Board to adopt a strategic plan that calls for convergence of Canadian Generally Accepted Accounting Principles with International Financial Reporting Standards over a five year period as outlined at Exhibit A1, Tab 6, Schedule 2. This development will potentially result in the removal of certain exemptions currently applicable to the accounting ~~of~~ for rate regulated entities. The accounting principles that are currently applied to the Company's financial statements allow for congruence between the actions of the regulator in the rate setting process and their consequential impacts on revenue, expense and earnings recognition as well as on the creation of assets and liabilities. This congruence will be diminished as a result of these forthcoming changes.

27. The Company faces federal and provincial legislative risk as well. The Ontario government is now set to implement the highest energy efficiency standards in Canada under new building code provisions.[5] All homes built in and after 2012 will have to meet EnerGuide 80 standards. Changes to the Ontario building code will be phased in by the Ministry of Municipal Affairs and Housing beginning next year. Depending on the nature of the incentive regulation framework to be introduced for

[5] Ministry of Municipal Affairs and Housing, "New 2006 Building Code", June 2006

2008, the Company may be at risk of further declines in average use over the period of the incentive regulation framework due to the phase in of these new guidelines.

f. Credit Rating Risk

28. General economic conditions can have a significant impact on the volumes consumed by EGD's customers. Structural breaks in the economy, for example, SARS and the August Blackout, are unavoidable. The impacts of events such as these can have a negative impact on volume consumption. Should other one time events such as these occur in the future, the Company may be at risk of a credit downgrade. Dominion Bond Rating Service (DBRS) recently noted in a presentation dated May 2003 that:

> ...Canadian utilities have less 'safety margin' than U.S., and are vulnerable to a quick downgrade if something goes wrong.[6]

Coverage ratios for the Company have significantly deteriorated since 1993 as shown in Table 4 presented later in this evidence. A sudden structural break and substantial loss in volumes either currently or prospectively could reduce earnings and result in a quick credit downgrade given the current financial risks faced by the Company.

Capital Structure Overview

29. The Company's evidence above describes the changes in the business and operating environment since the utility's equity thickness was last reviewed by the Board for the 1993 Test Year. In particular, the volatility in natural gas prices that has developed over the past 5 to10 years has had extensive material impacts on a

[6] Dominion Bond Rating Service, "The Rating Process and Cost of Capital for Utilities", May 2003

number of aspects of the utility business. These include the variability in customer demand due to conservation and competitive risks of fuel switching, the impact on short term liquidity requirements for the utility, and a weaker credit profile for the utility business due to the overall increase in business risks. The business risks and equity thickness analysis in this evidence and the Company's application are based on the current forecast test year cost of service regulatory environment that applies to the utility and may find the need for further review in an incentive rate environment.

30. It is important to note that a company's business risks must be taken into account when a company establishes its target capital structure and, in particular, its equity thickness which has a direct impact on the financial integrity of the company. The reason for this is that as a utility providing an important infrastructure service, a utility must maintain a strong capital attraction standard to have ready access to financial markets in all stages of a business cycle to meet its capital needs and customer service obligations. If the utility's access to capital markets is constrained, its financial integrity would be in jeopardy and it may not be able to provide the essential services to its customers.

31. As a simple overview, a company's target capital structure is an appropriate mix of debt and equity. The reason for this analysis starts with the fact that debt investors are given a legal priority in payment of interest and principal over payments to equity holders, but typically receive a lower return than equity investors in exchange for this priority of payment. However, there is no specific mathematical formula to dictate a precise mix of each type of capital that would be appropriate for any particular company. In addition, there are "hybrid" types of capital, such as

preferred shares and subordinated debt, that have debt like features as well as some equity like features and in some cases may also be an appropriate form of capital to include in a company's target capital structure.

32. Theoretically, there are an infinite number of permutations or combinations of capital that a company could chose to manage its financial risk. In practice, financial markets have established a relatively narrow range of the proper mix of debt and equity for a given industry, with company specific factors influencing the location for a specific entity within the industry range. In order to achieve the desired balance of debt and equity, the most important factor is the nature of the company's business risks and how much volatility and uncertainty is associated with these risks and the magnitude of their impact on the company's earnings.

33. In simple terms, a company with significant business risks will have greater earnings volatility and require a correspondingly higher level of equity. The reason for this is that a higher risk company will have more difficulty in attracting capital, particularly debt investors who may not receive their interest income when earnings are low. If the volatile market conditions lead to a longer period of low earnings, the company will run out of cash or liquidity to pay not only the debt investors' interest, but also, in severe cases, their principal repayment may be jeopardized and the company could be forced into bankruptcy.

34. On the other hand, a company with a very stable and predictable earnings level will usually have very few material business risks and be able to support a higher level of debt in its capital structure. In this case, debt investors are relatively confident that they will receive regular interest payments with little principal repayment risk. Most regulated utilities are in this category and typically have a relatively high

proportion of debt in the capital structure compared to other industries, which ultimately benefits rate payers through a lower total cost of capital.

35. In summary, a company's business risks combined with a company's financial risks to establish the total investment risk. The total investment risk is used to determine the capital structure weightings to provide the required financial integrity and capital attraction standards appropriate for a particular company. This assumes that the costs of each of these capital types are appropriately established by the market (or regulator) for investments of similar overall business and financial risk.

Credit Ratings

36. While this is a very high level view of how a company establishes a target capital structure, there are a number of other factors that are assessed by the market and ultimately lead to a rating of a company's financial strength. A detailed credit analysis is a complex combination of quantitative and qualitative measures that are evaluated and weighted to assign a credit rating for a particular company. However, the one of the most important factors that will impact a company's credit assessment is the capital structure. Moreover, as this is something that a company's management has control over, management can control to a significant degree the company's credit quality and access to capital. In the case of Enbridge Gas Distribution, it has obtained credit ratings from two agencies that specialize in evaluating the credit quality of debt issuers, DBRS and Standard and Poor's ("S&P"). Enbridge Gas Distribution is currently assigned a credit rating of "A" by DBRS and "A-"(A minus) by S&P. The credit rating reports on Enbridge Gas Distribution by these agencies and their rating scales are filed at Exhibit A3, Tab 8, Schedule 1.

Witnesses: B. Boyle
J. Denomy

37. As noted above, a credit analysis involves an assessment of a number of financial metrics, such as debt to total capital ratio ("Debt to Total Capital"), and Earnings Before payment of Interest expense and income Taxes interest coverage ("EBIT Interest Coverage"). This last ratio is defined as a company's Earnings Before payment of Interest expense and Income taxes (often referred to as "EBIT"), divided by the company's interest expense.

38. The EBIT Interest Coverage ratio is extremely important because it is an indication of how much of an "error margin" debt investors see in the company's net operating earnings before the company will be unable to pay its interest expense.

39. Table 4 below shows the Enbridge Gas Distribution Ontario utility EBIT Interest Coverage ratio based on the allowed capital structure and costs of capital from the Board decision since 1993. As these are all based on normal weather, they represent normalized coverage ratios. The derivation of the figures presented in Table 4 is provided in Appendix 1 and is described in detail in the "Explanatory Notes" material provided for Appendix 1.

TABLE 4

Col. 1	Col. 2 Test Year	Col. 3 Normalized Allowed Utility EBIT Interest Coverage Per Board Decision (times interest coverage)	Col. 4 EBIT Margin Above 2 Times Coverage ($ Millions)
1.	1993	2.38	48.0
2.	1994	2.33	43.7
3.	1995	2.34	47.4
4.	1996	2.37	55.7
5.	1997	2.36	57.5
6.	1998	2.30	48.2
7.	1999	2.23	38.6
8.	2000	2.23	33.2
9.	2001	2.20	32.0
10.	2002	2.24	33.6
11.	2003	2.18	27.5
12.	2004*	NA	NA
13.	2005	2.19	29.8
14.	2006	2.10	16.8

* Due to the nature of the application for the 2004 test year (rates were escalated) there is no Board approved capital structure for this year.

40. The table clearly identifies the alarming decline in the EBIT Interest Coverage ratios from 1993, which is the last time the Company's equity thickness was specifically reviewed by the Board, the utility's financial strength has weakened considerably leaving very little "margin of error" for actual results relative to forecast. Not surprisingly, during this period both credit rating agencies have downgraded the credit rating of Enbridge Gas Distribution. DBRS first downgraded the Company from "A (high)" to "A" in January 2001 and S&P followed in December of 2001 with a downgrade from "A" to "A-"(A minus). The rationale for the downgrades was clearly

Witnesses: B. Boyle
J. Denomy

linked to the increased business risks and weaker financial ratios as noted by DBRS in their January 9, 2001 press release as follows:

> DBRS is downgrading The Consumers' Gas Company Ltd.'s commercial paper rating to R-1 (low), long-term debt rating to "A" and preferred share credit rating to Pfd-2, with Stable trends, from R-1 (middle), A (high) and Pfd-2 (high), respectively. The ratings adjustments are based on the following considerations. Earnings volatility from traditional business risks such as weather and economic conditions has increased as a percentage of base earnings following the transfer of ancillary businesses to affiliates during F2000 and due to a decline in approved ROEs over the last 5 years. The steady decline in approved ROEs, consistent with the trend in long-term interest rates, has adversely affected earnings over the period. These factors, in combination, have resulted in a decline in certain key financial ratios from weather normalized historical highs. An expected slowdown in the Canadian economy could potentially lead to a further decline in interest rates and approved ROEs. While working capital needs have increased recently due to a very sharp increase in the cost of natural gas inventories that are generally financed with short-term debt, DBRS expects little material change in balance sheet leverage given the nature of the industry. The Company's primary challenge remains its earnings sensitivity to weather, given that roughly 70%-75% of distribution volumes are delivered to temperature sensitive residential and commercial customers. While the forecasting methodology adjusts for variations so that the earnings impact is moderated over a 5-year period, temperature variability can contribute to material short-term earnings volatility and can significantly affect key financial ratios. The Company's long-term outlook remains favourable, given one of the most attractive business franchises in Canada characterized by strong economic fundamentals.

41. Despite the decline in interest rates over the past five years, the utility's financial ratios, earnings volatility, and overall credit quality have continued to deteriorate such that the Company is at significant risk of a further and more serious credit rating downgrade. If S&P were to downgrade Enbridge Gas Distribution, the utility would fall into the "BBB" (triple B) category.

42. This is significant because many investors or investment funds have investment criteria that prohibit or limit the ownership of any debt with a rating below the "A" category. This would cause an immediate sale of the Company's outstanding debt held by such institutions and would lead to a significant reduction in Enbridge Gas Distribution's access to capital and increase the cost of borrowing.

43. Although sufficient access to capital would probably still be available in the strong segment of an economic cycle, this access would certainly be constrained in the weaker segments of a full economic cycle.

44. Restricted access to capital would result in increased borrowing cost, which can be estimated by referencing corporate borrowing spreads for BBB rated credits (currently about 10 to 20 basis points or 0.10% to 0.20% in higher annual interest rates for a 10 year medium term note, but can be much higher when capital market conditions are weak).

45. Furthermore, the reduced access to capital could reasonably lead to constraints on the Company's ability to add customers and meet service obligations. Moreover, once a credit rating has slipped below the "A" level, it is very difficult to recover that drop.

Financial Covenants and Trust Indenture

46. Each time Enbridge Gas Distribution issues term debt, it enters into a contract with the purchasers, or "holders", of the new debt. This contract, referred to as a trust indenture, contains a number of conditions that each of the parties must abide by as long as the debt is outstanding. The trust indenture can be different for each specific debt issue and every debt issuer will have different obligations depending on the credit quality of the company and the market conditions at the time of the issuance. Enbridge Gas Distribution enjoys relatively favourable terms in its current trust indenture due to its "A" category credit rating and has been able to use a similar trust indenture for all of its outstanding term debt.

47. Generally, the most significant obligations for an issuer in its trust indenture are the financial obligations, or "covenants", that the issuer agrees to abide by until it repays the debt. For Enbridge Gas Distribution, its most stringent financial covenant is a "new issue" test contained in Section 5.04, paragraph (5). Under this covenant, the Company has agreed that it will not issue any term debt (defined as debt with a maturity date of 18 months or more after the date of issue of the debt) unless the Company's consolidated net earnings before interest expense and income taxes (similar to EBIT) shall have been at least two times the long term debt interest expense for any twelve consecutive months out of the last twenty-three months. This calculation is essentially equivalent to the Company's EBIT Interest Coverage ratio.

48. The rationale for the interest coverage financial test is that it gives the debt investors some comfort that the Company will not take on additional debt when its financial performance deteriorates to a level that puts the interest payment at risk. The reason for the "twelve consecutive out of the last twenty-three month" allowance in the test is to provide some leeway in case of a one-time material unfavourable event.

49. As the Company's credit position has weakened since the last equity thickness review, its "margin of error" from business risk volatility in its actual earnings compared to forecast earnings to still meet the new issue interest coverage financial covenant has decreased dramatically as shown in Table 4. This demonstrates clearly that the Company's access to capital is much more likely to be constrained than at any time in its history.

Witnesses: B. Boyle
J. Denomy

50. In fact, based on actual weather for the first quarter of 2006 which reduced earnings before interest expense and income taxes (EBIT) by $33.3 million, Enbridge Gas Distribution will not meet the new issue test covenant for any twelve month period that includes January 2006 to March 2006. Without a change to the utility's capital structure for Fiscal 2007, an unfavourable reduction in forecast EBIT of $16.8 million or more in 2007 will prevent Enbridge Gas Distribution from having open access to the long term debt market.

51. The business risks such as lower than expected average uses, large volume customer fuel switching or plant closures, are overshadowed by weather, the greatest and most volatile risk for the utility. The impact of weather on the utility's EBIT since 1993 is shown in Table 5 below:

TABLE 5

Col. 1	Col. 2 Test Year	Col. 3 Impact of Actual vs Forecast Weather on Utility Earnings Before Interest Expense and Income Taxes* ($ Millions)	Col. 4 Absolute Value of Weather Impact on EBIT ($ Millions)
1.	1993	10.6	10.6
2.	1994	30.1	30.1
3.	1995	(30.1)	30.1
4.	1996	29.6	29.6
5.	1997	2.3	2.3
6.	1998	(70.0)	70.0
7.	1999	(55.0)	55.0
8.	2000	(38.9)	38.9
9.	2001	8.5	8.5
10.	2002	(47.3)	47.3
11.	2003	72.0	72.0
12.	2004	37.5	37.5
13.	2005	0.0	0.0
14.	2006 Q1	(57.7)	57.7
15.	Total	(107.4)	
16.	Average	(7.7)	35.0

* A positive number indicates colder than forecast weather and higher than forecast earnings and a negative number (bracketed and bolded) indicates warmer than forecast weather and lower than forecast earnings.

52. Since 1993, the average annual impact of weather on the utility's EBIT on an absolute value basis has been $35.0 million, significantly higher than the $16.8 million error margin reflected in the 2006 rates. Also of note is the fact that while there has been a roughly equal number of "colder than forecast" and "warmer

than forecast" years, the cumulative impact of weather since 1993 has been a reduction of over $107 million in utility EBIT due to actual weather being warmer than forecast weather.

Requested Equity Thickness

53. Based on:

a) the increased business and financial risks that have developed for Enbridge Gas Distribution over the last 10 to15 years described in this evidence and at Exhibit E2, Tab 1, Schedule 2,
b) the foreseeable challenge to issuing new long term debt; and
c) the looming risk of a credit rating downgrade, the Company believes that the utility's capital structure must be adjusted to increase the deemed equity ratio from 35.0% to 38.0%.

54. The justification for the 38.0% level is the utility's critical need to maintain a capital attraction standard that provides access to term debt markets at all stages of an economic cycle, in order to ensure that the utility's customers have the capital needed for the projects they require, at the best possible cost.

55. In order to continue to benefit from this open access, the utility must maintain its "A" credit rating and must be able to meet its new issue trust indenture covenant. At a 35.0% deemed equity ratio and current interest rates, Enbridge Gas Distribution does not have an adequate "margin of error" in actual versus forecast earnings to have reasonable confidence in meeting its new issue test covenant and is at risk for further credit rating downgrades.

56. Enbridge Gas Distribution believes that in the current business risk and financial market environment, it must have an EBIT interest coverage of at least 2.2 times to provide adequate room for weather and normal business volatility and be able to

maintain its credit strength and capital market access throughout a business cycle. The Company's requested deemed equity ratio of 38.0% just achieves this minimum target as shown in Table 6 below and thus is an appropriate level for the utility to maintain at this time.

TABLE 6

Item No.	Approved Equity Thickness	EBIT Interest Coverage Ratio (times)	EBIT Margin Above 2 Times Coverage ($MM)	Change in Requested Deficiency ($MM)
1 – Company Requested	38%	2.23	38.1	$0.0
2 – Scenario A	37%	2.18	31.0	($3.6)
3 – Scenario B	36%	2.14	23.9	($5.9)
4 – Scenario C	35%	2.10	16.8	($9.5)

Comparison to Other Canadian Utilities

57. Enbridge Gas Distribution is a relatively large local gas distribution utility with a premium franchise territory and a diversified customer base. Its capital structure, business risk, financial risk, trust indenture covenants and credit profile are specific to the Company and are appropriately measured and analyzed on a standalone basis. Nonetheless, it is helpful to understand how Enbridge Gas Distribution's financial position compares to other premier Canadian utilities and industry trends.

58. The Company notes that TransCanada Pipelines Ltd. had its deemed equity thickness increased from 30.0% to 33.0% effective January 1, 2001 by the National Energy Board in its RH-4-2001 Decision and further increased from 33.0% to 36.0%

in the RH-2-2004 Decision effective January 1, 2004. In addition, the British Columbia Utilities Commission approved an increase in equity thickness for Terasen Gas Inc. from 33.0% to 35.0% effective January 1, 2006 in its G-14-06 Decision. Enbridge Gas Distribution believes that a direct comparison of its business and financial risks and resulting capital structure relative to these utilities is ultimately not relevant due to the unique and specific capital structure needs of the Company that must be determined in this application. However, the Company does believe that this information is helpful to provide context for the general direction and industry trends with respect to Canadian utility capital structures.

59. The Company is aware that Union Gas has recently agreed in their 2007 rate application (EB-2005-0520) to a utility deemed common equity thickness increase from 35.0% to 36.0%. The Company is also aware that Union's agreement to the 36% equity thickness was part of a comprehensive financial package regarding financial matters and that there were compromises made by all parties in order to reach this agreement on all the financial issues. However, based on the 36.0% equity thickness and Union Gas' normalized cost of capital forecast, Union Gas indicated that it does not expect to meet its new term debt issue financial covenant in 2007 and will rely on short term debt capital or possibly the use of a preferred share issue to meet its funding needs during this period (EB-2005-0520 Tr. Volume 1, pp 18, lines 10 to 15). Enbridge Gas Distribution recognizes that this funding approach can be done for a temporary period in a strong corporate credit environment which the capital markets are experiencing in mid-2006. However, Enbridge Gas Distribution believes that it is more prudent and cost effective to fund long term utility assets with long term capital. The use of short term capital to fund long term utility assets is not a sustainable financing strategy for such assets and issuing preferred shares would likely burden ratepayers with higher costs in future

years. Enbridge Gas Distribution believes that the core financial integrity issue must be addressed and that it is most appropriate to address the issue before any of the adverse risks develop that could increase the cost of restoring the utility's financial integrity.

Conclusion

60. Enbridge Gas Distribution's business risks have increased have its financial integrity has declined over the last few years to the point where the Company is in jeopardy of losing its open access to long term capital markets and its credit rating may be downgraded. This would cause a restriction in access to capital to fund needed utility facility enhancement, and lead to an increase the utility's cost of capital, and a related increase in the rates charged to customers. Consequently, Enbridge Gas Distribution is requesting an increase in the utility's common equity thickness from 35.0% to 38.0% effective January 1, 2007 to restore the financial integrity of the utility to the level required to enable the Company to sustain access to long term capital on reasonable terms and prudently manage its business risks.

Witnesses: B. Boyle
J. Denomy

Glossary of Terms

Basis Point	One-hundredth of a percentage point, used in reference to interest rates or rates of return on equity
Bond Rating	A quality rating assigned by credit rating agencies as an indication of creditworthiness
Business Risk	The risk attributed to the nature of a particular business activity (as distinct from financial risk). For pipelines, it typically includes supply, market, regulatory, competitive, and operating risks
Capital Attraction Standard	The aspect of the fair return standard that requires that the return of a regulated utility permit incremental capital to be attracted to the enterprise on reasonable terms and conditions
Capital Structure	The way in which a business is financed; generally expressed as a percentage breakdown of the types of capital employed
Cost of Service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Covenant	A specific obligation imposed by contract on a party
Deemed Capital Structure	A notional capital structure used for rate-making purposes that may differ from a company's actual capital structure
EBIT	A financial measure equal to the earnings before interest expense and income taxes of a business
EBIT Interest Coverage	The number of times that earnings for a given year, before interest expense and income taxes, covers the annual interest expense
Embedded Cost of Debt	The weighted-average historical cost of long-term debt outstanding

Witnesses: B. Boyle
J. Denomy

Fair Return Standard	A standard that should be examined when setting the return allowed to a company; it is comprised of the comparable investment, financial integrity and capital attraction standards
FFO Interest Coverage	A financial ratio calculated as the funds from operations over gross interest incurred before subtracting capitalized interest and interest income
FFO to Total Debt Ratio	A financial ratio calculated as the funds from operations over long term debt (including amount for operating lease debt equivalent) plus current maturities, commercial paper and other short-term borrowings
Financial Integrity Standard	The aspect of the fair return standard that requires that the return of a regulated utility enable the financial integrity of the regulated enterprise to be maintained
Financial Risk	The risk inherent in a company's capital structure; financial risk increases as the proportion of debt increases in relation to shareholders' equity
Funds from Operations (FFO)	The net income from a company's continuing operations plus depreciation, amortization, deferred income taxes, non-cash items, and interest expense
Investment Risk	The total of a company's business risk and financial risk
Market Risk	The business risk that stems from the overall size of the market and the market share that a pipeline is able to capture
Operating Risk	The risk to the income-earning capability that arises from technical and operational factors
Pro Forma	Describes a presentation of data, typically financial statements, where the data reflects the world on an 'as if' basis; for example, financial statements that are adjusted to reflect a projected transaction

Witnesses: B. Boyle
J. Denomy

Rate Base	The amount of investment on which a return is authorized to be earned; it typically includes plant in service plus an allowance for working capital
Regulatory Risk	The risk to the income-earning capability of the assets that arises due to the method of regulation of the company
Revenue Requirement	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Supply Risk	The risk that the physical availability of natural gas could affect a utility's income-earning capability
Trust Indenture	A contract between an issuer of debt and the holder of the debt with the terms and conditions of the contract monitored by a trustee

Witnesses: B. Boyle
J. Denomy

TAB 13

CME, CCC, SEC, VECC INTERROGATORY #5

INTERROGATORY

E - Cost of Capital
Issue E2: Is the proposed change in capital structure increasing Enbridge's deemed common equity component from 36% to 42% appropriate?

Reference: EGDI Evidence E2, Tab 2, Schedule 1, report of Concentric Energy Advisors.

a) Please provide the CVs of the authors of the Concentric report.

RESPONSE

a) Please see the attachment.

Witnesses: J. Coyne
J. Lieberman
Concentric

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the power and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy, capital costs, valuation, fuels, and power markets. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and jurisdictions in Alberta, British Columbia, California, Connecticut, Massachusetts, New Jersey, Ontario, Maine, Texas, Vermont, and Wisconsin. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony and Litigation Experience

- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Terasen Utilities: provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District; provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)

- ATCO Utilities: primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board' policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values.
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2011)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Financial and Economic Advisory Experience

- Advisor to a major international corporation in the strategic evaluation of the SmartGrid related business segments, and development of specific investment and acquisition options in those business segments. (2011)
- Advisor to the New Brunswick Department of Energy on facilitating cross-border exports of energy from the Canadian Maritimes to Northeast U.S. markets. (2008-2011)
- Financial advisor to a major international corporation for investments in U.S. nuclear generating units. (2007-2009)
- Lead regulatory and market due diligence advisor to Macquarie Securities in the $7.4 billion acquisition of Puget Sound Energy. (2007)

- Retained by five Vermont electric utilities to study the comparative economics building the next generation of electric power generation within the state. Working with the utilities, the Vermont Department of Public Service, and the Electric Power Research Institute (EPRI), ten possible generation technologies were analyzed for their economic and environmental attributes. Costs were compared across technologies, and financial impacts including credit rating were examined. The report was presented in public forums and before state agencies. (2007)
- Advisor to the City of Mesa, Arizona for the potential privatization of the City's electric utility. (2007-2008)
- Independent Market Expert for a large Midwestern utility seeking a credit rating for its electric generation subsidiary. Providing a complete PJM and MISO market assessment and forward financial projections for the company's generation business including over 13,000 MW's of generating capacity. Financial projections are based on LMP price projections for the PJM-MISO interconnect, fuels prices, air emissions prices, and complete financial analysis of the business unit. Also provided support for discussions with the major credit rating agencies in conjunction with an investment bank and independent engineer. (2005-2006)
- Completed financial advisory services to a private equity consortium on the successful acquisition of a gas-fired power generating facility. The engagement included evaluation of all revenue streams, confirmation of investment economics under alternative market scenarios, and support for negotiations on key terms. (2005)
- Engaged by Goldman Sachs to assist with the financial and industry due diligence associated with the acquisition of Zilkha Renewable Energy, a wind energy company with over 20 projects under development. (2005-2006)
- Engaged by the State of Vermont to study of the feasibility of acquiring 550MW of hydroelectric generation facilities from USGen-New England. Completed a valuation of the assets, researched financing options with alternative tax-exempt and taxable structures, monitored the status of NEG's bankruptcy proceedings, researched comparable large-scale municipalizations, studied the potential in-state and out-of-state uses for the power, and tested the market for power sales to regional utilities. Facilitated discussions with companies for equity partnership, as well as for the purposes of providing power marketing and O&M services to the project. In addition to in-house consulting staff, compiled a team of legal, engineering and financing experts to deliver a comprehensive work product reflecting all aspects of the risks and benefits of purchasing this unique set of assets out of bankruptcy. (2003-2004)
- Evaluated a major utility's unregulated energy services business units and advised management on valuation and the potential market for the businesses. Developed offering materials and represented the company in negotiations with a potential buyer. (2001-2002)
- Lead advisor in the auction of Conectiv's $875 million in fossil and nuclear electric generation assets to NRG, PSE&G, and Exelon. Provided expert testimony before the New Jersey Board of Public Utilities on the auction process and asset values. (1999-2002)
- Provided financial and market analysis to Provincial Auditor of Ontario in examination of the long-term lease arrangement for the Bruce nuclear facility between Ontario Hydro and British Energy. (2002)
- For a private equity firm, evaluated on investment in a manufacturer of electric generation equipment. Analyzed the company's sustainable technological advantage, interviewed major customers, assessed competitor positioning, and provided market and revenue projections for the investment evaluation. (1999)
- Served as technical and market advisor for an investment consortium in the evaluation of an investment in five cogeneration plants. Analyzed fuel and off-take contracts, regulatory risk, plant operating procedures, and management personnel. Provided revenue and cost projections, supported bank discussions, and assisted bid negotiations. (1998)

- Co-advisor to Sithe Energies in the auction of the company's North American assets to Reliant and Exelon, and the marketing of its assets in Australia and Asia. (1999-2000)
- Lead advisor in the electric restructuring, auction of generating assets, and long-term power contracting for Denton Municipal Electric. Conducted regular briefings for the City Council. (1999-2001)
- Co-advisor to Sierra Pacific Resources in the proposed auction of 3,000 MW of fossil generating assets. (1999-2000)
- Co-advisor to TXU in the proposed auction of 560 MW of fossil generating assets. (2000)
- Co-advisor to Boston Edison (NSTAR) in the auction of $536 million in fossil generating assets to Sithe Energy. (1997-1998)
- Co-advisor to GPU in the auction of $1.7 billion in fossil generating assets to Sithe Energy. (1997-1998)
- Lead advisor to Bangor Hydro Electric Company in the auction of $90 million in hydroelectric, transmission, and fossil generating assets to PP&L Global. (1998-1999)

Business Strategy Experience

- Retained by a major Canadian electric company to study the cross-border transmission constraints into U.S. power markets and identify strategic options and transmission investments for expanding capacity and energy flows into these markets. (2007)
- Retained by the Western Electric Coordinating Council's (WECC) Board of Directors to facilitate the development of the WECC's five-year strategic plan. WECC is one of eight regional electric reliability organizations in North America, with 180 members across 14 states, and portions of Canada and Mexico. Leading the effort for Concentric, the planning process entails interviewing key stakeholders, facilitating discussion within and across member groups, gathering and presenting research, and making recommendations to the Board on the Strategic Plan. (2007)
- Engaged by a Canadian based utility company to develop its business strategy for growth in the U.S. Working with senior management, providing both a "big picture" strategic assessment of driving forces and opportunities in distribution, transmission and generation, supported by more detailed evaluation of specific investment options for presentation and discussion with its Board. (2005-2007)
- Advisor to Cook Inlet Regional, Inc., an Alaskan Native corporation, for the purpose of developing wind energy projects within the State of Alaska. (2006)
- Advisor to Tamarack Energy, Inc., for the purpose of developing renewable energy projects in the Northeast U.S. (2006)
- Engaged by a major Japanese corporation to provide assistance with the strategic evaluation of its ability to enter the $400 billion power and gas trading market. Management in Tokyo and New York required an independent assessment of the new and complex U.S. market for power and natural gas, and a determination of the company's ability to successfully compete. (2005-2006)
- Retained by an international power company to assist with evaluation of its corporate strategy and financial performance. Evaluated the company's corporate strategy using modern portfolio management tools to determine the inherent risk/reward trade-offs in the company's business portfolio. Analyzed core drivers of movements in the company's stock price and assisted the management team with engaging the Board of Directors in a strategic evaluation of the company's electric business. (2004)
- Strategic advisor to a major Public Power Authority in its evaluation of alternative business strategies and organizational structure. Provided industry benchmarking and qualitative analysis of various public power models for the Authority and developed future industry scenarios. Collaborated with

team of legal and banking advisors in examining restructuring options to maximize benefits to the Authority's stakeholders. (2004-2005)

- Provided analysis for the FirstEnergy Board of Directors regarding the potential economic impact of the 2003 power outage. (2003)
- Provided a strategic assessment of an eastern utility's electric generation and marketing business. The strategic assessment included: analysis of wholesale and retail electric markets in PJM, NE and NY markets, capacity, energy and ancillary service products, transmission and congestion, customers for wholesale products, competitors, short-term and long-term financial measures of viability, and factors for success. The engagement involved brainstorming sessions with the client team, research and analysis, and concluded with a report and evaluation of the company's strategic options and business prospects. (2003)
- Developed a cost of capital and investment decision-making framework for the company's new business investments. (2002)
- Strategic advisor to a Mid-Atlantic Utility in the development and implementation of the company's generation and marketing business. (1999-2000)

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- Utility Strategy and Shareholder Return (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998
- "New Market Dynamics," New England-Canada Business Council Annual Meeting, November 1996
- "Fuels Markets and Generation Choices," Electric Power Research Institute Seminar, Charleston, SC, October 1989
- "Issues Underlying the Long-Term Outlook for Natural Gas Markets," International Association for Energy Economics' International Conference, Calgary, Canada, July 1987

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 - current

Julie Lieberman
Project Manager

Ms. Lieberman is a financial and economic consultant with over 25 years of experience in the energy industry. Her broad base of experience includes: financial and economic consulting in the energy sector, utility ratemaking, regulatory policy and compliance, due diligence and litigation support and analysis, risk management, asset valuation and modeling, wholesale and retail energy trading and operations, energy procurement and scheduling, and utility hedging strategies. She has performed a variety of economic analyses, extensive regulatory research and assisted in the preparation of testimony and research reports in both regulatory and non-regulatory proceedings. Ms. Lieberman has performed focused regulatory research on issues pertaining to cost of capital, consolidated tax savings adjustments, risk-mitigating rate mechanisms, and Dodd Frank legislation and its implications for the end-use energy sector. Ms. Lieberman is proficient in Microsoft Office applications, Crystal Ball, and SPSS and has used option modeling, Monte Carlo simulations, and VAR analysis in a variety of risk applications. Prior to joining Concentric, Ms. Lieberman served in the financial and risk related fields in the unregulated energy trading and marketing sector. She holds a Masters in Finance from Boston College, a B.S. in Accounting from Indiana University, is a licensed CPA (Texas), and is a FINRA licensed securities professional (Series 7, 63, and 79).

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation

Ms. Lieberman has assisted in the development of expert testimonies and analyses in a number of utility regulatory proceedings before state and provincial regulatory commissions, and the FERC in the areas of: cost of capital, consolidated tax savings, marginal cost, alternative regulation, prudence and regulatory policy. Specific analyses performed to determine the return on equity have included: Discounted Cash Flow analysis (perpetual growth and variable rate growth methods), CAPM analysis, Risk Premium analysis, Comparable Earnings analysis, multiple and single variable Regression Analysis; and analyses related to business risk and flotation costs. Ms. Lieberman has conducted in depth studies on disparities between rates of return in the U.S. and Canada for Canadian regulators and their constituents; and has assisted in developing a recommended framework for establishing rates of return in Canada. Ms. Lieberman has performed extensive analyses of specific business risks as they relate to cost of capital, including: demand elasticity and declining use per customer and risk mitigation measures embedded in utility rates; and has conducted in-depth research and analyses of jurisdictional regulatory environments and applicable precedents as they relate to cost of service and utility rate making.

Representative engagements have included:

- Provided in-depth research and drafted testimony on FERC policy towards rate of return for new transmission investment for the owners of a newly-constructed regulated transmission line. (2011, 2007)

- Performed research and analyses and assisted in development of testimony on jurisdictional treatment of consolidated tax savings in Texas for CenterPoint Houston. (2010)
- Assisted Climate Change Central of Alberta with extensive research regarding pertinent Alberta legislation and DSM funding mechanisms in other jurisdictions that may support rate-base funding for DSM and renewable programs in the Province, and documented findings in a Report. (2010)
- Provided written comments and analyses on behalf of Enbridge and participated in an expert panel before the OEB in the Board's consultative process to determine whether its cost of capital formula was generating reasonable returns in the context of the prevalent economic downturn. (2009)
- Assisted in the development of written testimony and analyses for Oncor regarding the return of and on capital, consolidated tax savings adjustments, merger effects, and changing business environments. (2008)
- Assisted with the preparation of comments on behalf of a consortium of Massachusetts electric and gas utilities in response to MA DPU inquiry on a generic decoupling measure. (2008)
- Performed regulatory policy research for Southwestern Public Service Co. on the precedent for consolidated tax savings adjustments in the U.S. and its implications on regulatory principles for determining fairness and utility cost of service. (2007)
- Assisted in the development of an automatic adjustment formula for Green Mountain Power's return on equity to be used in its Alternative Regulation Rate Plan. (2006)
- Performed extensive research and assisted in the development of testimony related to the prudence of OG&E's acquisition of the McClain generating facility and developed an accompanying white paper on competitive bidding practices in the U.S. (2005)

Risk Management

Ms. Lieberman has performed extensive research on emerging regulatory policy and legislation impacting the energy sector, specifically Dodd-Frank and the emergence of carbon markets in the U.S. In her regulatory and ratemaking assignments, she has advised clients on the mechanics of risk-mitigating rate mechanisms pertaining to decoupling and cost recovery. Ms. Lieberman has been engaged to assess the adequacy of system processes and controls from a risk perspective and has conducted a variety of analyses that include an assessment and quantification of risk. Ms. Lieberman served in the risk management and commodity procurement areas in the unregulated natural gas energy trading and marketing sector. In addition, while with Ernst & Young in Houston, Ms. Lieberman specialized in the audit of wholesale energy trading entities, marking trading books to market, and performing detailed internal control assessments for a number of large energy exploration, production, trading, and marketing concerns.

Representative engagements have included:

- Assisted a confidential utility client in supporting a regulatory challenge to their hedging activity by commission staff (DOC, Minnesota). The staff asked the Company to explain how they approached hedging with particular focus on the role of implied volatility in making hedging determinations. (2011)
- Assessed the likely dispatch and overall spark spread opportunity of a proposed generation facility in Connecticut; developed a solicitation for a power off-take agreement for a 10-15 year term and performed a quantitative evaluation of bid responses. (2008)
- Developed a model and rigorous analyses to assess the value of the optional take provisions of certain power purchase agreements and their associated swap contract hedges in support of expert

testimony on the issues of damages in connection with a failed transaction for the sale of a portfolio of power contracts. (2005)

- Assisted in the modeling and valuation of a portfolio of power purchase agreements held by National Grid, using independent Monte Carlo simulation models and forecast assumptions for a range of variables and scenarios. (2004)
- Assisted in the development of a model to estimate gas market price effects and damages attributable to the trading activity of a market participant suspected of gas market manipulation in the Western energy markets in the period from 2000-2001. (2004)

Litigation Support

Supported development of expert testimony in various energy related arbitrations. Issues addressed include, standards of conduct, and energy economics. Services provided also included, economic modeling, collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, and assisting in the preparation of written testimony.

- Performed research and analyses around the valuation impact of "Round Trip Trades" on a trading entity's IPO price in connection with a shareholder initiated litigation. Research involved extensive fact discovery in the proceeding, prevalence of wash trading in the industry, and exploration of prevailing valuation methodologies used by investment banks connected with the IPO. (2005)
- Performed extensive fact discovery, research and analyses in support of Shearman & Sterling/Merrill Lynch in a litigation against Allegheny Energy Supply, which led to the development of expert testimony on behalf of Merrill Lynch, relating to liability and damages for due diligence disclosures. (2004-2005)

Management and Operations Consulting

Ms. Lieberman possesses direct financial and operational experience in the natural gas and energy trading industries enabling the delivery of significant value to clients. Ms. Lieberman has conducted detailed internal control reviews for a variety of clients primarily in the energy production, marketing, distribution and mining sectors, focusing on understanding business processes and value drivers to help clients obtain objectives.

Representative engagements have included:

- Performed an assessment of a large gas LDC's gas operating system to identify where control deficiencies were present and provided recommendations to address deficiencies. (2010-2011)
- Directed a review of the accounting, risk, and reporting processes associated with a gas distribution utility's unregulated natural gas transactions; identified weaknesses and proposed solutions. (2008)

Transaction Related Financial Advisory Services

Ms. Lieberman has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative engagements have included:

- Assisted in the development of a valuation of desalination facilities in California for corporate accounting purposes. (2008)

TAB 14

CME INTERROGATORY #1

INTERROGATORY

F - Revenue Sufficiency/Deficiency
Issue F2: Is the overall change in revenue requirement reasonable given the impact on consumers?

Reference: Energy Probe Interrogatory F.1
Line 18 of Exhibits E3, Tab 1, Schedule 1, E4, Tab 1, Schedule 1 and E5, Tab 1, Schedule 1
Line 16 of Exhibits F3, Tab 1, Schedule 1, F4, Tab 1, Schedule 1 and F5, Tab 1, Schedule 1
Exhibit B, Tab 1, Schedule 2 in each of the following proceedings:
EB-2009-0055; EB-2010-0042; EB-2011-0008; EB-2012-0055
Exhibit J2.4 in EB-2011-0277
Union Gas Exhibit J.O-4-14-1 in EB-2011-0210

Throughout the evidence filed by EGD, elements of the proposed 2013 revenue requirement are compared to elements of the 2007 Board approved revenue requirement, as well as to actual expenditures in years prior to 2013.

In order to enable us to evaluate the appropriateness of the revenue requirement and revenue deficiency amounts EGD asks the Board to approve for 2013, and, in particular, whether gains achieved under incentive regulation are reflected in EGD's proposed 2013 revenue requirement, what we seek is a spreadsheet presentation that starts with the elements of the Board approved 2007 revenue requirement and then tracks the causes of the revenue requirement sufficiencies or deficiencies achieved year-by-year from 2007 to 2012 inclusive so that all of this information can be considered alongside the elements of the proposed revenue requirement for 2013.

Attachment 1 to Union Gas Limited's ("Union") response to a CME Interrogatory in its Rebasing case (copy attached) depicts the format of the initial spreadsheet presentation we seek.

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

To be clear, we are seeking a presentation by EGD of its actual revenue sufficiency/deficiency amounts in each of the years 2007 to 2012 inclusive based on the approved benchmark Return on Equity ("ROE") for each of those years under the Incentive Regulation Mechanism ("IRM") Agreement. The ROE that EGD uses as the "Approved" Equity Return in its revenue sufficiency/deficiency presentations for 2011 and 2012 in Exhibits E and F at Tabs 3, 4 and 5; as well as in its presentations in its Earnings Sharing Mechanism ("ESM") calculations for 2008 to 2012 inclusive at Exhibit B, Tab 1, Schedule 2 in each of the proceedings described in the above reference is that benchmark return plus the 100 basis points of ROE deadband to which EGD is entitled under the ESM in the IRM Plan.

In these circumstances, it appears that the "Gross Sufficiency" amounts that EGD presented in Exhibit J2.4 in the EB-2011-0277 proceeding of $11.2M for 2008, $38.6M for 2009, $34.7M for 2010, and $28.1M for 2011 may be understated. We are unclear as to whether these amounts represent the Gross Sufficiency derived from use of the benchmark ROE's for each of those years as the measure of the "Approved" ROE, or a lower Gross Sufficiency that results from using the benchmark ROE in each of those years, plus the 100 basis points of earnings sharing deadband as the "Approved" ROE. The 100 basis points deadband is not a component of "Approved" ROE. It is a component of the ESM.

Having regard to the foregoing, would EGD please provide the following information:

(a) Clarification of whether the Gross Sufficiency for 2008, 2009, 2010 and 2011 presented in materials filed in its ESM proceedings for each of those years reflects the benchmark ROE in each of those years as shown in line 41 of Exhibit B, Tab 1, Schedule 2 in each of those proceedings of:

(i) 8.66% for 2008;

(ii) 8.31% for 2009;

(iii) 8.37% for 2010;

(iv) 7.94% for 2011; and

(v) 7.52% for 2012 (as shown in Exhibit M1, Tab 1, Schedule 1, para.9);

(b) If the Gross Sufficiency amounts presented by EGD in Exhibit J2.4 in EB-2011-0277 do not reflect the benchmark ROEs described above, then

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

please provide the Gross Sufficiency amounts for each of the years 2008 to 2011 inclusive and for 2012 estimated that derive from the use of the benchmark ROE for each of those years;

(c) A summary schedule in spreadsheet format that starts with a column containing each of the line items to be provided in EGD's response to Energy Probe Interrogatory F.1 requesting a presentation in a format similar to that provided by Union in Exhibit A2, Tab 6, Schedule 2 of EB-2011-0210, followed by columns containing the information for actual years 2007 to 2012 inclusive, followed by the 2013 column requested in Energy Probe Interrogatory F.1. The format of this presentation should be similar to Attachment 1 to Union's response to CME Interrogatory Exhibit J.O-4-14-1 in EB-2011-0210;

(d) For each of the columns 2007 actual to 2012 estimated actual, please provide the following additional information in a revenue deficiency/sufficiency format, including a brief description, by line item, of the cost for:

(i) 2007 Actuals being less than 2007 Board Approved elements of the revenue requirement presentation;

(ii) 2008 Actuals differing from 2007 Actuals;

(iii) 2009 Actuals differing from 2008 Actuals;

(iv) 2010 Actuals differing from 2009 Actuals;

(v) 2011 Actuals differing from 2010 Actuals;

(vi) 2012 Estimated Actuals differing from 2011 Actuals; and

(vii) 2013 Elements of Revenue Requirement differing from 2012 Estimated Actuals.

(e) For each of the line item explanations in each year provided in response to the previous question, please identify the portion of each line item that represents an efficiency or productivity gain compared to the previous year and whether that productivity or efficiency gain continues into the following year;

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

(f) For each of the line item explanations in each year to be provided above, please identify items of gain that were neither efficiency nor productivity gains, and describe the factors that gave rise to savings that were neither productivity nor efficiency related such as the following:

(i) An initial under-forecast of revenues; and/or

(ii) An initial over-forecast of expenses.

(g) For each of the years 2007 to 2012 inclusive, please provide a summary presentation identifying the major causes of the revenue sufficiencies achieved in each of those years. For example, if the gross revenue sufficiencies for 2009 and 2010 are $38.6M and $34.7M as shown in Exhibit J2.4 in EB-2011-0277, and not some higher number, then what we are interested in is a statement summarizing the major causes for each of those revenue sufficiency amounts in each of those years and as well for years 2007, 2008, 2011 and 2012;

(h) In the summaries of the major causes for the revenue deficiencies in each year, please indicate the extent to which the drivers of the sufficiency in each year are sustainable in 2013.

RESPONSE

(a) The gross sufficiency calculations for each of the years 2008 through 2012 were shown and determined in comparison to the Board approved formula ROE%'s each year plus 100 basis points. This is necessary for the purpose of determining the proper level of overearnings and overearnings subject to earnings sharing. The 100 basis point ROE dead-band within the 2008 Incentive Regulation ("IR") approved agreement was in effect an allowed or permitted required % of ROE in the same way that the co-efficient GDPIPI multiplier was an embedded and required productivity factor. EGD's IR mechanism recognized and includes an imposed inflation offset or productivity factor on the allowed or approved revenues which was clearly understood would not match the inflation factor aspect being incurred within costs. The result was that the IR model parameters clearly accepted embedded annual rate increases of approximately 50% of inflation with the knowledge and acceptance that the Company's ROE results were permitted to

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

be a maximum of 100 basis points above the typical Board formula ROE for the purpose of measuring overearnings. To disregard that accepted and permitted ROE % level for the purpose of determining overearnings while recognizing all other accepted parameters of the IR rate making model is incorrect and inappropriate.

(b) The gross sufficiency amounts calculated before earnings sharing when derived using the Board approved formula ROE%s for each year without recognizing the 100 basis point allowed ROE% dead-band are shown in Row 20 of Attachment 1.

(c) Please see Attachment 1.

(d) Please see Attachment 2 for the requested variances. For explanations of differing amounts requested in items (vi) & (vii) please see Exhibits C1, Tab 2, Schedule 1 & Exhibit D1, Tab 3, Schedule 1. For items (ii), (iii), (iv) & (v) the explanations provided within and used in the previous ESM proceedings mentioned above have been provided within Attachments 3.1 to 3.4

(e) For explanations of productivity and efficiencies please see Exhibit I, Issue O3, Schedule 5.2.

(f) There are a variety of items where increases or decreases have occurred year to year which may or may not be considered direct efficiencies or productivities. However, the year to year changes in those items are likely to have been influenced by other factors or decisions which therefore cannot be categorized as having occurred because of initial under or over forecasts. For example, annual depreciation expense change shown at line 19 of Attachment 2, has increased at a greater or lower pace in some years than previous years but mostly at a greater pace than that budgeted and included in base year IR amounts. The changing pace of annual depreciation change is influenced by changes in annual capital and timing changes which will never be the same as the base year. Another example is the ROE formula change year over year. The ROE year over year impact is not only influenced by the formula element change but also the annual change in rate base and associated change in equity.

(g) As previously indicated in each of EGD's ESM proceedings during the 2008-2012 IR term, other than the cost of service annual Y-factor inclusions and exclusions

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

within the derivation of rates, yearly rates and revenues are not approved based upon any examination or approval of a supporting level of specific types and mixes of costs. EGD provided information in each of the previous ESM proceedings comparing its earnings results to the cost elements last approved in 2007 and to anticipated revenue and margin changes resulting from the use of the IR formula each year. Drivers of sufficiencies and deficiencies cannot be determined for IR results in the same fashion that one is able to determine drivers within a year-over-year cost of service framework where revenues are underpinned by Board Approved costs.

(h) See part (g)

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei
M. Lister

Enbridge Gas Distribution

Financial Summary including Derivation of Revenue Sufficiency / (Deficiency)

Line No	Particulars ($Millions)	Col. 1 2007 Board Approved	Col. 2 2007 Actual	Col. 3 2008 Actual	Col. 4 2009 Actual	Col. 5 2010 Actual	Col. 6 2011 Actual	Col. 7 2012 Bridge	Col. 8 2013 Test
	Distribution & Gas Commodity Revenue								
1	Gas sales	2,369.1	2,274.3	2,351.6	2,221.6	1,988.0	1,978.4	2,158.8	2,004.1
2	Transportation	748.8	732.0	747.3	627.7	460.1	411.2	361.4	313.9
3	Storage	1.9	1.1	1.8	1.6	1.4	1.5	1.7	1.7
4	Total Distribution & Gas Commodity Revenue	3,119.8	3,007.4	3,100.7	2,850.9	2,449.5	2,391.1	2,521.9	2,319.7
5	Cost of Gas	2,174.6	2,047.7	2,137.8	1,862.6	1,450.7	1,383.7	1,515.5	1,307.9
6	Gas Distribution Margin	945.2	959.7	962.9	988.3	998.8	1,007.4	1,006.4	1,011.8
7	Other Revenue	34.5	39.7	43.5	48.4	53.7	41.2	40.2	38.9
8	Total Distribution, Commodity, & Other Revenue	979.7	999.4	1,006.4	1,036.7	1,052.5	1,048.6	1,046.6	1,050.7
	Distribution Operating Expenses								
9	Operating and maintenance expenses	326.2	322.0	323.4	336.9	346.2	360.5	402.2	438.1
10	Depreciation	227.3	225.7	236.7	251.0	266.9	276.6	291.6	300.8
11	Other financing	1.3	3.2	1.0	6.8	5.1	3.1	2.5	2.3
12	Municipal, capital and other taxes	45.9	43.6	44.8	44.4	40.7	37.6	38.8	40.1
13	Income taxes	85.8	91.3	87.3	78.7	71.3	57.0	34.0	45.4
14	Notional utility account recovery	9.2	9.2	-	-	-	-	-	-
15	Tax savings through 2012, CCCISRSDA in 2013	-	-	7.4	9.6	16.0	22.3	25.6	(4.6)
16	Return	284.0	273.9	284.6	269.8	268.6	256.8	255.9	299.6
17	Total Distribution Cost of Service Including Return	979.7	968.9	985.2	997.2	1,014.8	1,013.9	1,050.6	1,121.7
18	Net Revenue Sufficiency/(Deficiency)*	-	30.5	21.2	39.5	37.7	34.7	(4.0)	(71.0)
19	Provision for Income Taxes on Sufficiency/(Deficiency)	-	17.2	10.5	19.5	17.0	13.7	(1.4)	(21.6)
20	Gross Revenue Sufficiency/(Deficiency)*	-	47.7	31.7	59.0	54.7	48.4	(5.4)	(92.6)

* Sufficiency/deficiency amounts calculated for 2008 through 2012 have not incorporated the 100 basis point allowance, above the Board approved formula ROE, approved as part of the Company's incentive regulation framework, nor do they incorporate actual earning sharing amounts returned to ratepayers.

Enbridge Gas Distribution
Revenue Sufficiency / (Deficiency) Components

Line No	Particulars ($Millions)	Col. 1 2013 vs. 2007 BA	Col. 2 2007 vs. 2007 BA	Col. 3 2008 vs. 2007	Col. 4 2009 vs. 2008	Col. 5 2010 vs. 2009	Col. 6 2011 vs. 2010	Col. 7 2012 vs. 2011	Col. 8 2013 vs. 2012
	Distribution & Gas Commodity Revenue								
1	Gas sales	(365.0)	(94.8)	77.3	(130.0)	(233.6)	(9.6)	180.4	(154.7)
2	Transportation	(434.9)	(16.8)	15.3	(119.6)	(167.6)	(48.9)	(49.8)	(47.5)
3	Storage	(0.2)	(0.8)	0.7	(0.2)	(0.2)	0.1	0.2	-
4	Total Distribution & Gas Commodity Revenue	(800.1)	(112.4)	93.3	(249.8)	(401.4)	(58.4)	130.8	(202.2)
5	Cost of Gas	866.7	126.9	(90.1)	275.2	411.9	67.0	(131.8)	207.6
6	Gas Distribution Margin	66.6	14.5	3.2	25.4	10.5	8.6	(1.0)	5.4
7	Other Revenue	4.4	5.2	3.8	4.9	5.3	(12.5)	(1.0)	(1.3)
8	Total Distribution, Commodity, & Other Revenue	71.0	19.7	7.0	30.3	15.8	(3.9)	(2.0)	4.1
	Operating & maintenance expenses								
9	Pension	(35.6)	0.2	(0.2)	(0.9)	(1.4)	0.8	(17.4)	(16.7)
10	RCAM	(14.0)	-	(1.0)	(2.1)	(3.1)	(2.4)	(3.5)	(1.9)
11	DSM	(9.4)	-	(1.1)	(1.2)	(1.2)	(1.2)	(1.4)	(3.3)
12	Compensation	(49.1)	0.9	3.4	(5.0)	(3.1)	(14.6)	(15.1)	(15.6)
13	Internal allocations & recoveries	8.1	3.7	5.2	(2.3)	1.0	0.9	(0.6)	0.2
14	Provision for uncollectibles	(0.1)	(0.1)	(1.5)	(1.1)	6.3	(10.0)	7.8	(1.5)
15	Capitalization	30.1	(1.8)	(1.6)	0.6	3.0	2.7	17.0	10.2
16	Customer care	1.4	6.4	1.9	(5.0)	-	8.3	(11.2)	1.0
17	Other	(43.3)	(5.1)	(6.5)	3.4	(10.7)	1.2	(17.3)	(8.3)
18	Total operating & maintenance expenses	(111.9)	4.2	(1.4)	(13.6)	(9.2)	(14.3)	(41.7)	(35.9)
19	Depreciation	(73.5)	1.6	(11.0)	(14.3)	(15.9)	(9.7)	(15.0)	(9.2)
20	Municipal, capital, and other taxes	5.8	2.3	(1.2)	0.4	3.7	3.1	(1.2)	(1.3)
21	Notional utility account recovery	9.2	-	9.2	-	-	-	-	-
22	Rate base growth net of tax changes & debt costs	40.8	19.9	(13.1)	17.2	2.6	9.9	(2.2)	6.5
23	ROE formula change	(12.9)	-	(5.5)	7.2	(1.2)	8.6	8.3	(30.3)
24	Equity thickness change	(21.1)	-	-	-	-	-	-	(21.1)
25	Total Revenue Sufficiency/(Deficiency) Gross*	(92.6)	47.7	(16.0)	27.2	(4.2)	(6.3)	(53.8)	(87.2)

* The year to year change in sufficiency/deficiency amounts calculated for 2008 through 2012 have not incorporated the 100 basis point allowance, above the Board approved formula ROE, approved as part of the Company's incentive regulation framework, nor do they incorporate actual earning sharing amounts returned to ratepayers.

EGD
Contributors to Utility Earnings
and Earnings Sharing Amounts
for Fiscal Year 2008

Line No.		Col. 1 2008 Actual Normalized ($000's)	Col. 2 2007 Board Approved ($000's)	Col. 3 Over/ (Under) Earnings Impact ($000's)	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,353.4	2,369.1		
2.	Transportation revenue	747.3	748.8		
3.	Transmission, compression & storage	1.8	1.9		
4.	Gas costs	2,137.8	2,174.6		
5.	Distribution margin	964.7	945.2	19.5	a)
6.	Other revenue	38.9	34.3	4.6	b)
7.	Other income	4.3	0.2	4.1	c)
8.	O&M	323.4	326.2	2.8	d)
9.	Depreciation expense	236.7	227.3	(9.4)	e)
10.	Other expense	51.4	56.4	5.0	f)
11.	Income taxes	90.7	85.8	(4.9)	g)
12.	Utility Income	305.7	284.0	21.7	
13.	LTD & STD costs	161.6	165.8	4.2	h)
14.	Preference share costs	5.0	5.0	-	
15.	Return on Equity @ 9.66%[1] in 2008, 8.39% in 2007	131.4	113.2	(18.2)	
16.	Net Earnings Over / (Under)	7.7	(0.0)	7.7	
17.	Provision for taxes on Earnings Over / (Under)	3.9	(0.0)	3.9	
18.	Gross Earnings Over / (Under)	11.6	(0.0)	11.6	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,360.5			
20.	EGD normalized Earnings	139.1			
21.	EGD normalized Return on Equity	10.22%			

[1] 8.66% as per Board Approved formula using October 2008 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

2008 Earnings Sharing Amount and Contributors

The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1 of this schedule.

a) The distribution margin change of $19.5 million is mainly the result of the change in revenue derived from EGD's IR framework and formula (forecast 2008 IR formula revenue was $26.3 million, DRR beginning escalation formula was $753.2, end was $779.5), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower gas commodity pricing within the 2008 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive impact on earnings.

b) The other revenue change of $4.6 million is mainly due to increased late payment penalty revenue. This results in a positive impact on earnings.

c) The other income change of $4.1 million is mainly due to revenue from the management of fee for service external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

d) Utility O&M is $2.8 million below that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula. For a visual of the changes in utility O&M please see the updated evidence at Exhibit B, Tab 3, Schedule 1, Updated 2009-04-16. This results in a positive impact on earnings.

e) The increase in depreciation expense of $9.4 million is due to higher levels of property, plant, and equipment associated with customer growth and system improvement activities. This results in a negative impact on earnings.

f) Other expenses are lower mainly due to the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, a decrease in municipal and capital tax of $1.1 million mostly the result of decreased capital tax rates as recognized in the IR tax savings agreement and, a partial offsetting increase from recognition of EGD's $5.6 million share of the IR agreement tax savings impact within 2008 utility results. The net result has a positive impact on earnings.

g) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a negative impact on earnings.

h) The interest cost of utility long, medium and short term debt changed by $4.2 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive impact on earnings.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 HISTORICAL YEAR TO 2008 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2008 Actual	Col. 2 2008 Board Approved Budget	Col. 3 2008 Actual Over (Under) 2008 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 985.6	2 783.0	202.6
1.1.2	Rate 1 - T-Service	1 738.7	1 736.2	2.5
1.1	Total Rate 1	4 724.3	4 519.2	205.1
1.2.1	Rate 6 - Sales	1 815.6	1 619.0	196.6
1.2.2	Rate 6 - T-Service	2 263.9	2 147.1	116.8
1.2	Total Rate 6	4 079.5	3 766.1	313.4
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.7	(0.3)
1.3	Total Rate 9	2.2	2.7	(0.5)
1.	Total General Service Sales & T-Service	8 806.0	8 288.0	518.0
Contract Sales				
2.1	Rate 100	98.8	87.9	10.9
2.2	Rate 110	62.3	24.0	38.3
2.3	Rate 115	8.4	46.2	(37.8)
2.4	Rate 135	5.1	3.3	1.8
2.5	Rate 145	22.4	30.8	(8.4)
2.6	Rate 170	70.9	62.1	8.8
2.7	Rate 200	183.3	150.0	33.3
2.	Total Contract Sales	451.2	404.3	46.9
Contract T-Service				
3.1	Rate 100	494.0	569.7	(75.7)
3.2	Rate 110	602.2	588.9	13.3
3.3	Rate 115	627.4	854.9	(227.5)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.3	50.9	1.4
3.6	Rate 145	220.6	187.4	33.2
3.7	Rate 170	618.3	667.2	(48.9)
3.8	Rate 300	35.5	31.9	3.6
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 650.3	2 950.9	(300.6)
4.	Total Contract Sales & T-Service	3 101.5	3 355.2	(253.7)
5.	Total	11 907.5	11 643.2	264.3

* There is no distribution volume for Rate 125 customer.

** Less than 50,000 m³.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 HISTORICAL YEAR TO 2008 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2008 Actual	Col. 2 2008 Board Approved Budget	Col. 3 2008 Actual Over (Under) 2008 Budget (1-2)	Col. 4 2008* Adjustments	Col. 5 2008 Actual Over (Under) 2008 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 985.6	2 783.0	202.6	144.6	58.0
1.1.2	Rate 1 - T-Service	1 738.7	1 736.2	2.5	80.5	(78.0)
1.1	Total Rate 1	4 724.3	4 519.2	205.1	225.1	(20.0)
1.2.1	Rate 6 - Sales	1 815.6	1 619.0	196.6	94.5	102.1
1.2.2	Rate 6 - T-Service	2 263.9	2 147.1	116.8	116.7	0.1
1.2	Total Rate 6	4 079.5	3 766.1	313.4	211.2	102.2
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)	0.0	(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.7	(0.3)	0.0	(0.3)
1.3	Total Rate 9	2.2	2.7	(0.5)	0.0	(0.5)
1.	Total General Service Sales & T-Service	8 806.0	8 288.0	518.0	436.3	81.7
Contract Sales						
2.1	Rate 100	98.8	87.9	10.9	1.8	9.1
2.2	Rate 110	62.3	24.0	38.3	0.1	38.2
2.3	Rate 115	8.4	46.2	(37.8)	0.0 **	(37.8)
2.4	Rate 135	5.1	3.3	1.8	0.0	1.8
2.5	Rate 145	22.4	30.8	(8.4)	0.0 **	(8.4)
2.6	Rate 170	70.9	62.1	8.8	0.2	8.6
2.7	Rate 200	183.3	150.0	33.3	1.5	31.8
2.	Total Contract Sales	451.2	404.3	46.9	3.6	43.3
Contract T-Service						
3.1	Rate 100	494.0	569.7	(75.7)	5.6	(81.3)
3.2	Rate 110	602.2	588.9	13.3	1.3	12.0
3.3	Rate 115	627.4	854.9	(227.5)	0.0 **	(227.5)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	52.3	50.9	1.4	0.0	1.4
3.6	Rate 145	220.6	187.4	33.2	0.1	33.1
3.7	Rate 170	618.3	667.2	(48.9)	(8.7)	(40.2)
3.8	Rate 300	35.5	31.9	3.6	0.0	3.6
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	2 650.3	2 950.9	(300.6)	(1.7)	(298.9)
4.	Total Contract Sales & T-Service	3 101.5	3 355.2	(253.7)	1.9	(255.6)
5.	Total	11 907.5	11 643.2	264.3	438.2	(173.9)

*Note: Weather normalization adjustments have been made to the 2008 Actuals utilizing the 2008 Board Approved Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

The principal reasons for the variances contributing to the weather normalized decrease of 173.9 10^6m^3 in the 2008 Actual over the 2008 Board Approved Budget are as follows:

1. The volumetric decrease of 20.0 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 19.6 10^6m^3 and a customer shortfall of 0.4 10^6m^3;

2. The volumetric increase of 102.2 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 103.9 10^6m^3 and favourable customer variance of 2.4 10^6m^3; partially offset by a lower average use per customer totalling 4.1 10^6m^3;

3. The volumetric decrease of 0.5 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.5 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 255.6 10^6m^3 is due to decreases in the commercial sector of 189.8 10^6m^3 and the industrial sector of 107.7 10^6m^3; partially offset by increases in the apartment sector of 10.1 10^6m^3 and Rate 200 of 31.8 10^6m^3. The decrease is primarily attributable to net customer migration to General Service of 103.9 10^6m^3 as stated above, one large distributed energy customer with distribution volume of 90.7 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008, as well as production decreases and plant closures in the wake of an unexpected major financial crisis and a rapidly deteriorating economy since October 2008.

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2008

		Col. 1	Col. 2	Col. 3
Line No.	Particulars ($ 000's)	Actual 2008	Actual 2007	2008 Actual Over/(Under) 2007 Actual
1.	Finance	$ 5,843	$ 5,890	$ (47)
2.	Risk Management	1,695	2,448	(753)
3.	Customer Care Service Charges (including CIS)	84,583	87,569	(2,986)
4.	Customer Care Internal Costs	8,388	10,188	(1,800)
5.	Provision for Uncollectibles	16,660	15,205	1,455
6.	Energy Supply, Storage, Regulatory	19,471	22,562	(3,091)
7.	Legal and Corporate Services	1,147	1,069	78
8.	Operations	43,308	43,146	162
9.	Information Technology	21,247	21,637	(390)
10.	Business Development & Customer Strategy (excluding DSM)	14,656	13,828	828
11.	Human Resources (excluding benefits)	3,833	3,581	252
12.	Benefits	24,597	26,077	(1,480)
13.	Engineering	32,291	31,406	885
14.	Public and Government Affairs	5,484	5,070	414
15.	Non Departmental Expenses	29,497	23,396	6,101
16.	Corporate Allocations (including direct costs)	32,166	27,715	4,451
17.	Total	344,866	340,787	4,079
18.	Capitalization (A&G)	(21,643)	(21,238)	(405)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	323,223	319,549	3,674
20.	Demand Side Management Programs (DSM)	23,100	22,000	1,100
21.	Total Net Utility Operating and Maintenance Expense	$ 346,323	$ 341,549	$ 4,774

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS
FOR FISCAL YEAR 2009

Line No.		Col. 1 2009 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,221.6	2,369.1		
2.	Transportation revenue	627.7	748.8		
3.	Transmission, compression & storage	1.6	1.9		
4.	Gas costs	1,862.6	2,174.6		
5.	Distribution margin	988.3	945.2	43.1	a)
6.	Other revenue	40.9	34.3	6.6	b)
7.	Other income	7.5	0.2	7.3	c)
8.	O&M	336.9	326.2	(10.7)	d)
9.	Depreciation expense	251.0	227.3	(23.7)	e)
10.	Other expense	60.8	56.4	(4.4)	f)
11.	Income taxes	78.7	85.8	7.1	g)
12.	Utility Income	309.3	284.0	25.3	
13.	LTD & STD costs	152.9	165.8	12.9	h)
14.	Preference share costs	3.4	5.0	1.7	h)
15.	Return on Equity @ 9.31%[1] in 2008, 8.39% in 2007	127.2	113.2	(14.0)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	25.9	(0.0)	25.9	
17.	Provision for taxes on Earnings Over / (Under)	12.7	(0.0)	12.7	
18.	Gross Earnings Over / (Under)	38.6	(0.0)	38.6	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,366.0			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	153.0			
21.	EGD normalized Return on Equity	11.20%			

[1] 8.31% as per Board Approved formula using October 2008 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witness: K. Culbert

2009 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

1. The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1, Column 4, of this schedule.

   a) The distribution margin change of $43.1 million is mainly the result of the change in revenue derived from EGD's IR framework and formula where forecast cumulative 2009 IR formula revenue was an increase of $48.9 million from the base year DRR amount (beginning amount in 2008 was $753.2 million, ending amount in 2009 was $802.1 million), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2009 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive impact on earnings.

   b) The other revenue change of $6.6 million is due to increased late payment penalty revenue of $5.9 million, an increase in service charges of $1.4 million and a decrease in other revenue of $(0.7) million. This results in a positive impact on earnings.

   c) The other income change of $7.3 million is mainly due to revenue from the management fee for service, external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

   d) Utility O&M is $10.7 million above that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula.

Witness: K. Culbert

e) For an explanation of the details of utility O&M please see the evidence at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

f) The increase in depreciation expense of $23.7 million is due to higher levels of property, plant, and equipment associated within customer growth and system improvement activities in both 2008 and 2009, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvement Property Plant and Equipment in 2008 has a full year depreciation increase impact in 2009 while the increases relative to 2009 have a part year impact. The depreciation increases result in a reduction in earnings.

g) Other expenses increase of $4.4 million is the result of an increase in the recognition of EGD's $9.6 million share of the IR agreement tax savings impact within 2009 results, an increase in fixed financing costs of $5.2 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $1.5 million which is primarily due to decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

h) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a positive impact on earnings.

i) The interest cost of utility long, medium and short term debt and preference share costs changed by $14.6 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive impact on earnings.

Witness: K. Culbert

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 ACTUAL AND 2009 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2009 Actual	Col. 2 2009 Board Approved Budget	Col. 3 2009 Actual Over (Under) 2009 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 119.7	2 896.6	223.1
1.1.2	Rate 1 - T-Service	1 625.8	1 705.0	(79.2)
1.1	Total Rate 1	4 745.5	4 601.6	143.9
1.2.1	Rate 6 - Sales	1 932.4	1 819.2	113.2
1.2.2	Rate 6 - T-Service	2 450.0	2 659.8	(209.8)
1.2	Total Rate 6	4 382.4	4 479.0	(96.6)
1.3.1	Rate 9 - Sales	1.1	2.1	(1.0)
1.3.2	Rate 9 - T-Service	0.2	0.5	(0.3)
1.3	Total Rate 9	1.3	2.6	(1.3)
1.	Total General Service Sales & T-Service	9 129.2	9 083.2	46.0
Contract Sales				
2.1	Rate 100	17.4	0.0	17.4
2.2	Rate 110	59.8	71.5	(11.7)
2.3	Rate 115	4.4	4.4	0.0
2.4	Rate 135	0.6	3.3	(2.7)
2.5	Rate 145	25.7	22.5	3.2
2.6	Rate 170	77.0	56.3	20.7
2.7	Rate 200	179.3	151.3	28.0
2.	Total Contract Sales	364.2	309.3	54.9
Contract T-Service				
3.1	Rate 100	82.9	0.0	82.9
3.2	Rate 110	517.8	619.5	(101.7)
3.3	Rate 115	460.1	532.1	(72.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	51.3	54.8	(3.5)
3.6	Rate 145	222.6	203.6	19.0
3.7	Rate 170	467.4	545.6	(78.2)
3.8	Rate 300	39.3	51.7	(12.4)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 007.3	(165.9)
4.	Total Contract Sales & T-Service	2 205.6	2 316.6	(111.0)
5.	Total	11 334.8	11 399.8	(65.0)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 ACTUAL AND 2009 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2009 Actual	Col. 2 2009 Board Approved Budget	Col. 3 2009 Actual Over (Under) 2009 Budget (1-2)	Col. 4 2009* Adjustments	Col. 5 2009 Actual Over (Under) 2009 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 119.7	2 896.6	223.1	141.0	82.1
1.1.2	Rate 1 - T-Service	1 625.8	1 705.0	(79.2)	70.6	(149.8)
1.1	Total Rate 1	4 745.5	4 601.6	143.9	211.6	(67.7)
1.2.1	Rate 6 - Sales	1 932.4	1 819.2	113.2	39.3	73.9
1.2.2	Rate 6 - T-Service	2 450.0	2 659.8	(209.8)	44.6	(254.4)
1.2	Total Rate 6	4 382.4	4 479.0	(96.6)	83.9	(180.5)
1.3.1	Rate 9 - Sales	1.1	2.1	(1.0)	0.0	(1.0)
1.3.2	Rate 9 - T-Service	0.2	0.5	(0.3)	0.0	(0.3)
1.3	Total Rate 9	1.3	2.6	(1.3)	0.0	(1.3)
1.	Total General Service Sales & T-Service	9 129.2	9 083.2	46.0	295.5	(249.5)
Contract Sales						
2.1	Rate 100	17.4	0.0	17.4	0.3	17.1
2.2	Rate 110	59.8	71.5	(11.7)	0.1	(11.8)
2.3	Rate 115	4.4	4.4	0.0	0.0 **	0.0
2.4	Rate 135	0.6	3.3	(2.7)	0.0	(2.7)
2.5	Rate 145	25.7	22.5	3.2	0.2	3.0
2.6	Rate 170	77.0	56.3	20.7	0.1	20.6
2.7	Rate 200	179.3	151.3	28.0	1.0	27.0
2.	Total Contract Sales	364.2	309.3	54.9	1.7	53.2
Contract T-Service						
3.1	Rate 100	82.9	0.0	82.9	1.2	81.7
3.2	Rate 110	517.8	619.5	(101.7)	1.5	(103.2)
3.3	Rate 115	460.1	532.1	(72.0)	0.1	(72.1)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	51.3	54.8	(3.5)	0.0	(3.5)
3.6	Rate 145	222.6	203.6	19.0	3.7	15.3
3.7	Rate 170	467.4	545.6	(78.2)	6.0	(84.2)
3.8	Rate 300	39.3	51.7	(12.4)	0.0	(12.4)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 007.3	(165.9)	12.5	(178.4)
4.	Total Contract Sales & T-Service	2 205.6	2 316.6	(111.0)	14.2	(125.2)
5.	Total	11 334.8	11 399.8	(65.0)	309.7	(374.7)

*Note: Weather normalization adjustments have been made to the 2009 Actual utilizing the 2009 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

** Less than 50,000 m^3

The principal reasons for the variances contributing to the weather normalized decrease of 374.7 10^6m^3 in the 2009 Actual over the 2009 Board Approved Budget are as follows:

1. The volumetric decrease of 67.7 10^6m^3 in Rate 1 was due to a lower average use per customer totalling 36.0 10^6m^3 and an unfavourable customer variance of 31.7 10^6m^3;

2. The volumetric decrease of 180.5 10^6m^3 in Rate 6 was due to net customer migration to Contract Sales and T-Service of 74.5 10^6m^3, unfavourable customer variance of 99.3 10^6m^3 and a lower average use per customer totalling 6.7 10^6m^3;

3. The volumetric decrease of 1.3 10^6m^3 in Rate 9 was due to a lower average use per station totalling 1.2 10^6m^3 and the loss of two stations of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 125.2 10^6m^3 was due to decreases in the commercial sector of 167.4 10^6m^3 and the industrial sector of 43.5 10^6m^3; partially offset by an increase in the apartment sector of 58.7 10^6m^3 and Rate 200 of 27.0 10^6m^3. The decrease was primarily attributable to production decreases and plant closures in the wake a of an unexpected major financial crisis and a rapidly deteriorating economy since October 2008.

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2009

Line No.	Particulars ($ 000's)	Col. 1 Actual 2009	Col. 2 Actual 2008	Col. 3 2009 Actual Over/(Under) 2008 Actual	Col. 4 Board Approved 2007 Utility O&M
1.	Finance	$ 5,981	$ 5,843	$ 138	$ 8,380
2.	Risk Management	2,865	1,695	1,170	1,986
3.	Customer Care Service Charges (including CIS)	82,042	84,583	(2,541)	83,493
4.	Customer Care Internal Costs	7,868	9,679	(1,812)	7,302
5.	Provision for Uncollectibles	17,855	16,660	1,195	15,105
6.	Energy Supply, Storage, Regulatory	19,016	19,471	(455)	21,904
7.	Legal and Corporate Services	1,170	1,147	23	1,207
8.	Operations	44,199	43,308	891	44,728
9.	Information Technology	22,695	21,247	1,448	21,790
10.	Business Development & Customer Strategy (excluding DSM)	14,255	13,364	891	19,118
11.	Human Resources (excluding benefits)	14,568	13,272	1,296	13,059
12.	Benefits	26,241	24,597	1,644	21,405
13.	Engineering	24,949	22,851	2,098	20,982
14.	Public and Government Affairs	5,764	5,484	280	5,760
15.	Non Departmental Expenses	30,899	29,497	1,403	17,305
16.	Corporate Allocations (including direct costs)	34,266	32,166	2,100	18,100
17.	Total	354,633	344,866	9,768	321,624
18.	Capitalization (A&G)	(23,902)	(21,643)	(2,259)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	330,731	323,223	7,508	304,200
20.	Demand Side Management Programs (DSM)	24,255	23,100	1,155	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 354,986	$ 346,323	$ 8,663	$ 326,200
22.	Regulatory Adjustments				
23.	To eliminate Corporate Cost Allocations above RCAM	(13,100)	(13,066)	(34)	
24.	To eliminate CIS fees above Customer Care settlement agreement	(4,900)	(9,811)	4,911	
25.	Total Adjustments	(18,000)	(22,877)	4,877	
26.	Utility O&M	$ 336,986	$ 323,446	$ 13,540	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) 2008 Actual and 2007 OEB approved O&M costs by department have been recasted to reflect the 2009 structure

Witness: R. Lei

EXPLANATION OF MAJOR CHANGES
ACTUAL 2009 O&M EXPENSES COMPARED TO ACTUAL 2008 O&M EXPENSES

The 2009 Actual Utility O&M was $337 million, which was $13.5 million higher than the 2008 Actual Utility O&M of $323.4 million. The increase was primarily driven by higher employee related costs, new CIS costs, provision for uncollectibles, and corporate cost allocations. The increased O&M costs were partially offset by higher A&G capitalization.

Line No:

2. Risk Management increased $1.2 million due to a $1.0 million insurance deductible payment related to an incident in 2009.

3. Customer Care Service Charges decreased $2.5 million due to lower old CIS fees, with new CIS hosting and support costs now residing in Information Technology.

4. Customer Care Internal Costs decreased $1.8 million due to lower Customer Care licenses and employee costs.

5. Provision for Uncollectibles increased $1.2 million due to higher write-offs of receivables as a result of the economic downturn.

9. Information Technology increased $1.4 million due to maintenance, lease, and support costs for the new CIS.

11. Human Resources (excluding Benefits) increased $1.3 million due to higher severance, labour arbitration, and facilities maintenance costs.

12. Benefits increased $1.6 million due to higher health and dental premiums, increased employee relocations, and costs of switching benefit carriers.

13. Engineering costs increased $2.1 million mainly from required increased pipeline inspections as well as incremental costs required for a new Technical Training department.

15. Non Departmental Expenses increased $1.4 million in relation to an increased variable compensation related expense.

16. Corporate Allocations increased $2.1 million largely due to higher stock based compensation.

18. A&G Capitalization increased $2.3 million due to higher employee related costs.

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUINTS
FOR FISCAL YEAR 2010

Line No.		Col. 1 2010 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	1,988.0	2,369.1		
2.	Transportation revenue	460.1	748.8		
3.	Transmission, compression & storage	1.4	1.9		
4.	Gas costs	1,450.7	2,174.6		
5.	Distribution margin	998.8	945.2	53.6	a)
6.	Other revenue	40.5	34.3	6.2	b)
7.	Other income	13.3	0.2	13.1	c)
8.	O&M	346.7	326.2	(20.5)	d)
9.	Depreciation expense	266.9	227.3	(39.6)	e)
10.	Other expense	61.8	56.4	(5.4)	f)
11.	Income taxes	71.2	85.8	14.6	g)
12.	Utility Income	306.0	284.0	22.0	
13.	LTD & STD costs	150.9	165.8	14.9	h)
14.	Preference share costs	2.1	5.0	2.9	h)
15.	Return on Equity @ 9.37%[1] in 2010, 8.39% in 2007	129.5	113.2	(16.3)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	23.6	(0.0)	23.6	
17.	Provision for taxes on Earnings Over / (Under)	10.6	(0.0)	10.6	
18.	Gross Earnings Over / (Under)	34.2	(0.0)	34.2	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,381.6			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	153.0			
21.	EGD normalized Return on Equity	11.08%			

[1] 8.37% as per Board Approved formula using October 2009 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witnesses: K. Culbert
R. Small

2010 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

1. The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1 of this schedule.

   a) The distribution margin change of $53.6 million is mainly the result of the change in revenue derived from EGD's IR framework and formula where forecast cumulative 2010 IR formula revenue was an increase of $64.9 million from the base year DRR amount (beginning amount in 2008 was $753.2, ending amount in 2010 was $818.1, EB-2009-0172 Rate Order Appendix A), increases in DSM and Customer Care related Y-Factors versus 2007 Board Approved levels and, partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2010 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive impact on earnings.

   b) The other revenue change of $6.2 million is due to increased late payment penalty revenue of $5.1 million, an increase in service charges of $1.7 million and a decrease in other revenue of $(0.6) million. This results in a positive impact on earnings.

   c) The other income change of $13.1 million is mainly due to revenue from the management of fee for service, external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

d) Utility O&M is $20.5 million above that of the 2007 approved level embedded in base rates used in the incentive regulation escalation formula. The details of utility O&M are provided at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

e) The increase in depreciation expense of $39.6 million is due to higher levels of property, plant, and equipment associated with customer growth and system improvement activities in each of 2008, 2009, and 2010, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvements in P.P.& E. in 2008 and 2009 has a full year depreciation increase impact in 2010, while the increases relative to 2010 have a part year depreciation increase impact. The depreciation expense increase results in a reduction to earnings.

f) Other expense increases of $5.4 million are the result of, an increase in recognition of EGD's $16.0 million share of the IR agreement tax savings impact within 2009 results, an increase in fixed financing costs of $3.8 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $5.2 million mostly the result of decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

g) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

h) The interest cost of utility long, medium and short term debt and preference share costs changed by $17.8 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2010 ACTUAL AND 2010 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2010 Actual	Col. 2 2010 Board Approved Budget	Col. 3 2010 Actual Over (Under) 2010 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 119.2	3 030.6	88.6
1.1.2	Rate 1 - T-Service	1 294.7	1 615.5	(320.8)
1.1	Total Rate 1	4 413.9	4 646.1	(232.2)
1.2.1	Rate 6 - Sales	1 959.3	1 990.4	(31.1)
1.2.2	Rate 6 - T-Service	2 382.7	2 445.3	(62.6)
1.2	Total Rate 6	4 342.0	4 435.7	(93.7)
1.3.1	Rate 9 - Sales	1.0	1.4	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.3	(0.2)
1.3	Total Rate 9	1.1	1.7	(0.6)
1.	Total General Service Sales & T-Service	8 757.0	9 083.5	(326.5)
Contract Sales				
2.1	Rate 100	4.8	0.0	4.8
2.2	Rate 110	69.1	43.9	25.2
2.3	Rate 115	(2.1)	4.4	(6.5)
2.4	Rate 135	5.6	5.9	(0.3)
2.5	Rate 145	22.0	25.2	(3.2)
2.6	Rate 170	37.8	79.7	(41.9)
2.7	Rate 200	169.6	156.1	13.5
2.	Total Contract Sales	306.8	315.2	(8.4)
Contract T-Service				
3.1	Rate 100	17.8	0.0	17.8
3.2	Rate 110	493.3	518.8	(25.5)
3.3	Rate 115	480.1	421.2	58.9
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	67.4	52.2	15.2
3.6	Rate 145	211.2	196.8	14.4
3.7	Rate 170	579.4	463.4	116.0
3.8	Rate 300	27.6	41.0	(13.4)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 876.8	1 693.4	183.4
4.	Total Contract Sales & T-Service	2 183.6	2 008.6	175.0
5.	Total	10 940.6	11 092.1	(151.5)

* There is no distribution volume for Rate 125 customers.

Witness: I. Chan

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2010 ACTUAL AND 2010 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2010 Actual	Col. 2 2010 Board Approved Budget	Col. 3 2010 Actual Over (Under) 2010 Budget (1-2)	Col. 4 2010* Adjustments	Col. 5 2010 Actual Over (Under) 2010 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	3 119.2	3 030.6	88.6	83.9	172.5
1.1.2	Rate 1 - T-Service	1 294.7	1 615.5	(320.8)	74.8	(246.0)
1.1	Total Rate 1	4 413.9	4 646.1	(232.2)	158.7	(73.5)
1.2.1	Rate 6 - Sales	1 959.3	1 990.4	(31.1)	48.6	17.5
1.2.2	Rate 6 - T-Service	2 382.7	2 445.3	(62.6)	70.2	7.6
1.2	Total Rate 6	4 342.0	4 435.7	(93.7)	118.8	25.1
1.3.1	Rate 9 - Sales	1.0	1.4	(0.4)	0.0	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.3	(0.2)	0.0	(0.2)
1.3	Total Rate 9	1.1	1.7	(0.6)	0.0	(0.6)
1.	Total General Service Sales & T-Service	8 757.0	9 083.5	(326.5)	277.5	(49.0)
Contract Sales						
2.1	Rate 100	4.8	0.0	4.8	0.0 **	4.8
2.2	Rate 110	69.1	43.9	25.2	0.1	25.3
2.3	Rate 115	(2.1)	4.4	(6.5)	0.0	(6.5)
2.4	Rate 135	5.6	5.9	(0.3)	0.0	(0.3)
2.5	Rate 145	22.0	25.2	(3.2)	0.6	(2.6)
2.6	Rate 170	37.8	79.7	(41.9)	0.3	(41.6)
2.7	Rate 200	169.6	156.1	13.5	6.0	19.5
2.	Total Contract Sales	306.8	315.2	(8.4)	7.0	(1.4)
Contract T-Service						
3.1	Rate 100	17.8	0.0	17.8	0.1	17.9
3.2	Rate 110	493.3	518.8	(25.5)	0.0 **	(25.5)
3.3	Rate 115	480.1	421.2	58.9	(0.1)	58.8
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	67.4	52.2	15.2	0.0	15.2
3.6	Rate 145	211.2	196.8	14.4	0.3	14.7
3.7	Rate 170	579.4	463.4	116.0	0.6	116.6
3.8	Rate 300	27.6	41.0	(13.4)	0.0	(13.4)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 876.8	1 693.4	183.4	0.9	184.3
4.	Total Contract Sales & T-Service	2 183.6	2 008.6	175.0	7.9	182.9
5.	Total	10 940.6	11 092.1	(151.5)	285.4	133.9

*Note: Weather normalization adjustments have been made to the 2010 Actual utilizing the 2010 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

** Less than 50,000 m^3

Witness: I. Chan

The principal reasons for the variances contributing to the weather normalized increase of 133.9 10^6m^3 in the 2010 Actual over the 2010 Board Approved Budget are as follows:

1. The volumetric decrease of 73.5 10^6m^3 in Rate 1 was due to a lower average use per customer totaling 76.1 10^6m^3; paritially offset by a favourable customer variance of 2.6 10^6m^3;

2. The volumetric increase of 25.1 10^6m^3 in Rate 6 was due to net customer migration from Contract Sales and T-Service of 106.7 10^6m^3 and a higher average use per customer totaling 76.3 10^6m^3; partially offset by an unfavourable customer variance of 157.9 10^6m^3;

3. The volumetric decrease of 0.6 10^6m^3 in Rate 9 was due to a lower average use per station totaling 0.4 10^6m^3 and the loss of four stations of 0.2 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 182.9 10^6m^3 was due to increases in the apartment sector of 21.7 10^6m^3, the commerical sector of 61.3 10^6m^3, the industrial sector of 80.4 10^6m^3 and Rate 200 of 19.5 10^6m^3. The increase was primarily attributable to lower gas prices than was budgeted.

Witness: I. Chan

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars ($ 000's)	Col. 1 Actual 2010	Col. 2 Actual 2009	Col. 3 Actual 2008	Col. 4 2010 Actual Over/(Under) 2009 Actual	Col. 5 Board Approved 2007 Utility O&M
1.	Finance	$ 6,016	$ 5,981	$ 5,843	$ 35	$ 8,380
2.	Risk Management	2,141	2,865	1,695	(724)	1,986
3.	Customer Care Service Charges	68,742	82,042	84,583	(13,300)	83,493
4.	Customer Care Internal Costs	9,222	7,868	9,679	1,354	7,302
5.	Provision for Uncollectibles	11,500	17,855	16,660	(6,355)	15,105
6.	Energy Supply, Storage, Regulatory	20,534	19,016	19,471	1,518	21,904
7.	Legal and Corporate Services	1,407	1,170	1,147	237	1,207
8.	Operations	50,060	44,199	43,308	5,861	44,728
9.	Information Technology	30,398	22,695	21,247	7,703	21,790
10.	Business Development & Customer Strategy (excluding DSM)	18,567	14,255	13,364	4,312	19,118
11.	Human Resources (excluding benefits)	15,127	14,568	13,272	559	13,059
12.	Benefits	27,335	26,241	24,597	1,094	21,405
13.	Engineering	27,891	24,949	22,851	2,942	20,982
14.	Public and Government Affairs	8,137	5,764	5,484	2,373	5,760
15.	Non Departmental Expenses	24,267	30,899	29,497	(6,632)	17,305
16.	Corporate Allocations (including direct costs)	36,692	34,266	32,166	2,426	18,100
17.	Total	358,036	354,633	344,866	3,403	321,624
18.	Capitalization (A&G)	(24,330)	(23,902)	(21,643)	(428)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	333,706	330,731	323,223	2,975	304,200
20.	Demand Side Management Programs (DSM)	25,468	24,255	23,100	1,213	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 359,174	$ 354,986	$ 346,323	$ 4,188	$ 326,200
22.	Regulatory Adjustments					
23.	To eliminate Corporate Cost Allocations above RCAM	(12,428)	(13,100)	(13,066)	672	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	(4,900)	(9,811)	4,900	
25.	Total Adjustments	(12,428)	(18,000)	(22,877)	5,572	
26.	Utility O&M	$ 346,746	$ 336,986	$ 323,446	$ 9,760	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.

Witnesses: R. Lei
A. Patel

EXPLANATION OF MAJOR CHANGES
ACTUAL 2010 O&M EXPENSES COMPARED TO ACTUAL 2009 O&M EXPENSES

The 2010 Actual Utility O&M was $346.7 million, which was $9.7 million higher than the 2009 Actual Utility O&M of $337.0 million. The increase was primarily driven by higher hosting and support costs for the new CIS, operational outside service costs, conservation service costs, and corporate cost allocations. The increased O&M costs were partially offset by lower (old) CIS hosting and support fees, and provision for uncollectibles.

Line No:

3. Customer Care Service Charges decreased $13.3 million due to the elimination of (old) CIS hosting and support fees from Customer Care, with (new) CIS hosting and support costs now residing in Information Technology.

4. Customer Care Internal Costs increased $1.4 million due to higher consulting costs.

5. Provision for Uncollectibles decreased $6.4 million due to the implementation of SAP which resulted in enhanced customer information.

6. Energy Supply, Storage, and Regulatory increased $1.5 million primarily due to higher well logging and compressor repair costs, and higher employee related costs.

8. Operations increased $5.9 million due to higher outside service costs, and higher employee costs.

9. Information Technology increased $7.7 million due to a full year of hosting and support fees for the new CIS versus partial 2009 year fees, and higher hardware/software maintenance costs.

Witnesses: R. Lei
A. Patel

10. Business Development & Customer Strategy increased $4.3 million due to higher conservation service costs.

12. Benefits increased $1.1 million due to higher pension plan expenses.

13. Engineering costs increased $3.2 million due to increased requirements for the Technical Training department, and increased Employee Health and Safety costs.

14. Public and Government Affairs increased $2.4 million primarily due to the transfer of the Ombudsman Office from Customer Care and incremental costs incurred, and from a customer relationship study conducted in 2010.

15. Non Departmental Expenses decreased $6.6 million in relation to decreased variable compensation related expenses.

16. Corporate Allocations increased $2.9 million primarily due to higher compensation related costs.

20. Demand Side Management increased $1.2 million due to the higher level of Board Approved program spending.

Witnesses: R. Lei
A. Patel

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS
FOR FISCAL YEAR 2011

Line No.		Col. 1 2011 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	1,978.4	2,369.1		
2.	Transportation revenue	411.2	748.8		
3.	Transmission, compression & storage	1.5	1.9		
4.	Gas costs	1,383.7	2,174.6		
5.	Distribution margin	1,007.4	945.2	62.2	a)
6.	Other revenue	40.6	34.3	6.3	b)
7.	Other income	0.8	0.2	0.6	c)
8.	O&M	360.5	326.2	(34.3)	d)
9.	Depreciation expense	276.6	227.3	(49.3)	e)
10.	Other expense	63.0	56.4	(6.6)	f)
11.	Income taxes	57.0	85.8	28.8	g)
12.	Utility Income	291.7	284.0	7.7	
13.	LTD & STD costs	141.5	165.8	24.3	h)
14.	Preference share costs	2.4	5.0	2.6	h)
15.	Return on Equity @ 8.94%[1] in 2011, 8.39% in 2007	127.3	113.2	(14.1)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	20.5	(0.0)	20.5	
17.	Provision for taxes on Earnings Over / (Under)	8.1	(0.0)	8.1	
18.	Gross Earnings Over / (Under)	28.6	(0.0)	28.6	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,424.5			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	147.8			
21.	EGD normalized Return on Equity	10.38%			

[1] 7.94% as per Board Approved formula using October 2010 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witnesses: K. Culbert
R. Small

2011 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1 of this schedule.

a) The distribution margin change of $62.2 million is mainly the result of the change in revenue derived from Enbridge Gas Distribution's IR framework and formula where forecast cumulative 2011 IR formula revenue was an increase of $76.9 million from the base year DRR amount (beginning amount in 2008 was $753.2, ending amount in 2011 was $830.1, EB-2010-0146 Rate Order Appendix A), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, significant and partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2011 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive earnings impact.

b) The other revenue change of $6.3 million is due to increased late payment penalty revenue of $5.2 million, an increase in service charges of $1.9 million and a decrease in other revenue of $(0.8) million. This results in a positive earnings impact.

c) The other income change of $0.6 million is mainly due to revenue from the management of fee for service external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

d) Utility O&M is $34.3 million above that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula. For a visual of the details of utility O&M please see evidence at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

e) The increase in depreciation expense of $49.3 million is due to higher levels of property, plant, and equipment associated within customer growth and system improvement activities in each of 2008, 2009, 2010, and 2011, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvement P.P.& E. in 2008, 2009 and 2010 has a full year depreciation increase impact in 2011 while the increases relative to 2011 have a part year depreciation increase impact. The depreciation increases result in a reduction in earnings.

f) Other expense increases of $6.6 million are the result of, an increase in recognition of EGD's $22.3 million share of the IR agreement tax savings impact, an increase in fixed financing and debt redemption premium costs of $1.8 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $8.3 million mostly the result of decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

g) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a positive earnings impact.

Witnesses: K. Culbert
R. Small

h) The interest cost of utility long, medium and short term debt and preference share costs changed by $26.9 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive earnings impact.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL AND 2011 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Actual	Col. 2 2011 Board Approved Budget	Col. 3 2011 Actual Over (Under) 2011 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 601.7	3 356.3	245.4
1.1.2	Rate 1 - T-Service	1 098.2	1 408.1	(309.9)
1.1	Total Rate 1	4 699.9	4 764.4	(64.5)
1.2.1	Rate 6 - Sales	2 323.2	2 235.7	87.5
1.2.2	Rate 6 - T-Service	2 396.8	2 282.7	114.1
1.2	Total Rate 6	4 720.0	4 518.4	201.6
1.3.1	Rate 9 - Sales	0.8	0.4	0.4
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)
1.3	Total Rate 9	0.9	0.6	0.3
1.	Total General Service Sales & T-Service	9 420.8	9 283.4	137.4
Contract Sales				
2.1	Rate 100	2.3	0.0	2.3
2.2	Rate 110	66.6	64.5	2.1
2.3	Rate 115	0.1	0.4	(0.3)
2.4	Rate 135	1.4	0.6	0.8
2.5	Rate 145	22.8	22.3	0.5
2.6	Rate 170	48.5	49.9	(1.4)
2.7	Rate 200	168.7	157.4	11.3
2.	Total Contract Sales	310.4	295.1	15.3
Contract T-Service				
3.1	Rate 100	8.0	0.0	8.0
3.2	Rate 110	479.5	407.4	72.1
3.3	Rate 115	558.5	512.7	45.8
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	60.0	49.4	10.6
3.6	Rate 145	161.5	215.0	(53.5)
3.7	Rate 170	474.1	513.3	(39.2)
3.8	Rate 300	30.5	30.0	0.5
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 727.8	44.3
4.	Total Contract Sales & T-Service	2 082.5	2 022.9	59.6
5.	Total	11 503.3	11 306.3	197.0

* There is no distribution volume for Rate 125 customers.

Witnesses: P. Baxter
I. Chan

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL AND 2011 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2011 Actual	Col. 2 2011 Board Approved Budget	Col. 3 2011 Actual Over (Under) 2011 Budget (1-2)	Col. 4 2011* Adjustments	Col. 5 2011 Actual Over (Under) 2011 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	3 601.7	3 356.3	245.4	(19.0)	226.4
1.1.2	Rate 1 - T-Service	1 098.2	1 408.1	(309.9)	(6.6)	(316.5)
1.1	Total Rate 1	4 699.9	4 764.4	(64.5)	(25.6)	(90.1)
1.2.1	Rate 6 - Sales	2 323.2	2 235.7	87.5	(36.4)	51.1
1.2.2	Rate 6 - T-Service	2 396.8	2 282.7	114.1	(21.0)	93.1
1.2	Total Rate 6	4 720.0	4 518.4	201.6	(57.4)	144.2
1.3.1	Rate 9 - Sales	0.8	0.4	0.4	0.0	0.4
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)	0.0	(0.1)
1.3	Total Rate 9	0.9	0.6	0.3	0.0	0.3
1.	Total General Service Sales & T-Service	9 420.8	9 283.4	137.4	(83.0)	54.4
Contract Sales						
2.1	Rate 100	2.3	0.0	2.3	0.0 **	2.3
2.2	Rate 110	66.6	64.5	2.1	0.0 **	2.1
2.3	Rate 115	0.1	0.4	(0.3)	0.0	(0.3)
2.4	Rate 135	1.4	0.6	0.8	0.0	0.8
2.5	Rate 145	22.8	22.3	0.5	0.0 **	0.5
2.6	Rate 170	48.5	49.9	(1.4)	0.0 **	(1.4)
2.7	Rate 200	168.7	157.4	11.3	1.5	12.8
2.	Total Contract Sales	310.4	295.1	15.3	1.5	16.8
Contract T-Service						
3.1	Rate 100	8.0	0.0	8.0	0.0 **	8.0
3.2	Rate 110	479.5	407.4	72.1	(0.2)	71.9
3.3	Rate 115	558.5	512.7	45.8	0.0 **	45.8
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	60.0	49.4	10.6	0.0	10.6
3.6	Rate 145	161.5	215.0	(53.5)	(0.5)	(54.0)
3.7	Rate 170	474.1	513.3	(39.2)	(1.5)	(40.7)
3.8	Rate 300	30.5	30.0	0.5	0.0	0.5
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 727.8	44.3	(2.2)	42.1
4.	Total Contract Sales & T-Service	2 082.5	2 022.9	59.6	(0.7)	58.9
5.	Total	11 503.3	11 306.3	197.0	(83.7)	113.3

*Note: Weather normalization adjustments have been made to the 2011 Actual utilizing the 2011 Board Approved Budget Degree Days in order to place the two years on a comparable basis.
** Less than 50,000 m

Witnesses: P. Baxter
I. Chan

The principal reasons for the variances contributing to the weather normalized increase of 113.3 10^6m^3 in the 2011 Actual over the 2011 Board Approved Budget are as follows:

1. The volumetric decrease of 90.1 10^6m^3 in Rate 1 was due to a lower average use per customer totalling 88.3 10^6m^3 and an unfavourable customer variance of 1.8 10^6m^3;

2. The volumetric increase of 144.2 10^6m^3 in Rate 6 was due to net customer migration from Contract Sales and T-Service of 66.9 10^6m^3 and a higher average use per customer totaling 231.9 10^6m^3; partially offset by an unfavourable customer variance of 154.6 10^6m^3;

3. The volumetric increase of 0.3 10^6m^3 in Rate 9 was due to a higher average use per station totalling 0.3 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 58.9 10^6m^3 was due to increases in the industrial sector of 74.7 10^6m^3, the commercial sector of 29.2 10^6m^3, the apartment sector of 9.1 10^6m^3 and Rate 200 of 12.8 10^6m^3; partially offset by net customer migration to General Service of 66.9 10^6m^3. The increase was primarily attributable to lower gas prices than budgeted and improved business conditions, leading to production line increases and plant expansion.

Witnesses: P. Baxter
I. Chan

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAITENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars ($ 000's)	Col. 1 Actual 2011	Col. 2 Actual 2010	Col. 3 Actual 2009	Col. 4 Actual 2008	Col. 5 2011 Actual Over/(Under) 2010 Actual	Col. 6 OEB Approved 2007 Utility O&M
1.	Finance	$ 6,196	$ 6,016	$ 5,981	$ 5,843	$ 180	$ 8,380
2.	Risk Management	2,459	2,141	2,865	1,695	318	1,986
3.	Customer Care Service Charges	64,190	68,742	82,042	84,583	(4,552)	83,493
4.	Customer Care Internal Costs	7,360	9,222	7,868	9,679	(1,862)	7,302
5.	Provision for Uncollectibles	21,542	11,500	17,855	16,660	10,042	15,105
6.	Energy Supply, Storage, Regulatory	11,757	12,587	11,827	12,368	(830)	14,900
7.	Legal and Corporate Security	4,146	1,407	1,170	1,147	2,739	1,207
8.	Operations	59,195	60,580	55,170	53,540	(1,385)	54,893
9.	Information Technology	30,893	30,398	22,695	21,247	495	21,790
10.	Business Development & Customer Strategy (excluding DSM)	15,631	18,567	14,255	13,364	(2,936)	19,118
11.	Human Resources (excluding benefits)	20,031	15,127	14,568	13,272	4,904	13,059
12.	Benefits	27,488	27,335	26,241	24,597	153	21,405
13.	Pipeline Integrity and Safety	29,695	25,318	21,167	19,722	4,377	17,820
14.	Public and Government Affairs	7,381	6,582	5,331	4,723	798	4,759
15.	Non Departmental Expenses	31,130	25,822	31,332	30,258	5,308	18,307
16.	Corporate Cost Allocations (including direct costs)	43,440	36,692	34,266	32,166	6,748	18,100
17.	Total	382,534	358,036	354,633	344,866	24,498	321,624
18.	Capitalization (A&G)	(24,482)	(24,330)	(23,902)	(21,643)	(152)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	358,052	333,706	330,731	323,223	24,346	304,200
20.	Demand Side Management Programs (DSM)	26,708	25,468	24,255	23,100	1,240	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 384,760	$ 359,174	$ 354,986	$ 346,323	$ 25,586	$ 326,200
22.	Regulatory Adjustments						
23.	To eliminate Corporate Cost Allocations above RCAM	(16,725)	(12,428)	(13,100)	(13,066)	(4,296)	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	-	(4,900)	(9,811)	-	
25.	To eliminate Conservation Services	(7,292)	-	-	-	(7,292)	
26.	Incremental O&M Allocated to Unregulated Storage	(233)	-	-	-	(233)	
27.	Total Adjustments	(24,249)	(12,428)	(18,000)	(22,877)	(11,821)	
28.	Utility O&M	$ 360,511	$ 346,746	$ 336,986	$ 323,446	$ 13,764	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations, and other utility adjustments.
2) Historical years including the 2007 OEB approved budget have been restated based on the 2011 organization structure.

Witnesses: R. Lei
A. Patel

EXPLANATION OF MAJOR CHANGES
ACTUAL 2011 O&M EXPENSES COMPARED TO ACTUAL 2010 O&M EXPENSES

The 2011 Actual Utility O&M was $360.5 million, which was $13.8 million higher than the 2010 Actual Utility O&M of $346.7 million. The increase was primarily driven by higher provision for uncollectibles, compensation costs, damage prevention, environmental, health and safety costs. The increased O&M costs were partially offset by lower customer care costs, operational outside service costs, and conservation services spending.

Line No:

3. Customer Care Service Charges: decreased by $4.6 million primarily due to lower bill and payment production costs and lower contract pricing.

4. Customer Care Internal Costs: decreased by $1.9 million as a result of lower consulting charges and licensing fees.

5. Provision for Uncollectibles: increased by $10.0 million mainly due to adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011.

7. Legal and Corporate Security: increased by $2.7 million resulting from the centralization of legal expenses in the Legal department.

8. Operations: decreased by $1.4 million primarily due to lower outside services, well logging work, and higher damage recovery.

10. Business Development & Customer Strategy: decreased by $2.9 million mainly due to lower conservation services spending. For the purposes of ESM, conservation services

are eliminated for utility O&M starting in 2011 since there is a separate sharing mechanism as per the Settlement Agreement on EB-2011-0008.

11. Human Resources: increased by $4.9 million primarily attributed to higher employee services and benefits, severances, and higher rents and leases.

13. Pipeline Integrity and Safety: increased by $4.4 million mainly due to higher damage prevention costs and Environment, Health, and Safety costs.

15. Non Departmental Expenses: increased by $5.3 million largely due to higher compensation related costs.

16. Corporate Cost Allocations: increased by $6.7 million primarily driven by higher compensation related costs and insurance premium.

20. Demand Side Management: increased by $1.2 million due to the higher level of Board Approved program spending.

Witnesses: R. Lei
A. Patel

TAB 15

CCC INTERROGATORY #1

INTERROGATORY

F - Revenue Sufficiency/Deficiency
Issue F2: Is the overall change in revenue requirement reasonable given the impact on consumers?

For each year 2007-2012(forecast) please provide a schedule setting out the allowed ROE, actual ROE and the dollar amounts of over-earnings. Also please provide the amounts of those over-earnings allocated to shareholder and ratepayers.

RESPONSE

Please see response provided in the attached Table A.

Witnesses: K. Culbert
R. Small

TABLE A

Line No		2007 Historical	2008 Historical	2009 Historical	2010 Historical	2011 Historical	2012 Bridge
1.	Allowed ROE (without 100bp ESM allowance)	8.39%	8.66%	8.31%	8.37%	7.94%	7.52%
2.	Actual Normalized ROE Before Earnings Sharing	10.72%	10.21%	11.20%	11.10%	10.38%	7.24%
3.	Gross Overearnings/(Underearnings) ($millions) (Note 1)	47.7	31.7	59.0	54.7	48.4	(5.4)
4.	Ratepayer Share of Gross Overearnings ($millions)	-	5.6	19.3	17.4	14.3	-
5.	Shareholder Share of Gross Overearnings/(Underearnings) ($millions) (Note 1)	47.7	26.1	39.7	37.4	34.1	(5.4)
6.	Actual Normalized ROE /After Earnings Sharing	10.72%	9.94%	10.26%	10.24%	9.66%	7.24%

Note 1: Amounts include impact of 100bp allowed for earnings sharing purposes during the 2008-2012 incentive term, additionally these are not true resulting net earnings amounts as they include tax amounts payable.

TAB 16

EGDI INTERROGATORY

Interrogatory #4

Please refer to the Evidence of Lawrence D. Booth, p. 3 (note, the first of two page 3's), lines 3-12, p.4, line 10, and Appendix A.

a. Please indicate whether Dr. Booth considers himself an expert on the regulatory and business risk of U.S. utilities

b. If yes, please provided the basis of those qualifications, and any studies he has produced on this topic.

c. Has Dr. Booth ever appeared as an expert witness before a US regulatory tribunal?

---

a) Dr. Booth has not yet been asked to testify as an expert Cost of Capital witness before a US regulatory tribunal.

b) His academic CV, extensive publications, the presentation of expert financial evidence before civil tribunals in other countries (including the U.S.) and his record as an expert witness before Canadian regulatory tribunals should be more than adequate to warrant his acceptance by U.S. regulatory tribunals as a person qualified to provide opinion evidence on the regulatory and business risks faced by U.S. utilities.

c) Dr. Booth has presented evidence in a civil case in the US that was settled.

TAB 17

Joseph L. Rotman School of Management
University of Toronto

Professor Laurence Booth
CIT Chair in Structured Finance

Rotman

HOME ADDRESS
Suite 802, 900 Yonge Street,
Toronto, Ontario, M4W 3P5.
E-Mail Booth@rotman.utoronto.ca
(416) 978-6311

OFFICE ADDRESS
University of Toronto
105 St George Street,
Toronto, Ontario M5S 3E6
(416) 971-3048 (Fax)

TEACHING AND RESEARCH INTERESTS. Main interest is teaching domestic and international corporate finance. Research interests centre on the cost of capital, empirical corporate finance and capital market theory.

ACADEMIC BACKGROUND:

D.B.A.,	Indiana University, (finance major).
M.B.A.,	Indiana University, (finance major).
M.A.,	Indiana University, (Economics).
B. Sc.(Econ),	London School of Economics.

AWARDS & HONOURS

MBA Second Year Instructor of the Year Award, 1996, 1998 (joint) & 2000
Best paper in corporate finance, 1999 SFA meetings
ASAC Distinguished Professor Address 1990,
Director Financial Management Association 1988-90,
English Speaking Union Fellow,
Fulbright,
Elected to Beta Gamma Sigma,
First class honours B.Sc.(Econ)
CBV (Chartered Business Valuator),
National Post Leader in Management Education Award 2003

ACADEMIC EMPLOYMENT: CIT Chair in Structured Finance (1999-), Professor of Finance, Rotman School of Management, University of Toronto (1987-Present), Visiting Professor Nankai University (China) 1989, the Czech Management Centre (1998), visiting scholar London School of Economics (1985).

TEACHING EXPERIENCE: Graduate (MBA) courses on The Economics of Enterprise, the Economic Environment of Business, Business Finance, Corporate Financing, International Financial Management, Mergers & Acquisitions, Financial Management, Capital Markets & Corporate

Financing (EMBA), Financial Theory of the Firm (Ph.D), Capital Markets Workshop (Ph.D). Undergraduate courses (B.Comm) in International Business and Business Finance. Executive courses (2-5 days) on Money and Foreign Exchange Markets, Business Valuation, Financial Strategy, Equity Markets, Capital Market Innovations, Mergers & Acquisitions and Finance for Non-Financial Managers.

JOURNAL ARTICLES

"Stochastic Demand, Output and the Cost of Capital: A Clarification," Journal of Finance, 35 (June 1980),

"Capital Structure, Taxes and the Cost of Capital," Quarterly Review of Economics and Business, 20 (Autumn 1980,

"Stock Valuation Models Under Inflation," Financial Analysts Journal, (May-June 1981),

"Market Structure, Uncertainty and the Cost of Equity Capital," Journal of Banking and Finance, (May 1981),

"Capital Budgeting Frameworks for the Multinational Corporation," Journal of International Business Studies, (Fall 1982),

"Hedging and Foreign Exchange Exposure," Management International Review, (Spring 1982),

"Correct Procedures for Discounting Risky Cash Outflows," Journal of Financial and Quantitative Analysis, (June 1982),

"Total Price Uncertainty and the Theory of the Competitive Firm," Economica, (May 1983),

"Portfolio Composition and the CAPM," Journal of Economics and Business, (June 1983),

"On the Negative Risk Premium for Risk Adjusted Discount Rates," Journal of Business Finance and Accounting, (Spring 1983),

"On the Unanimity Literature and the Security Market Line Criterion," Journal of Business Finance and Accounting (Winter 1983),

"Empirical Tests of the Monetary Approach to Exchange Rate Determination," (with R. Vander Kr,aats) Journal of International Money and Finance, (December 1983), "The Ex-Dividend Day Behaviour of Canadian Stock Prices: Tax Changes and Clientele Effects," Journal of Finance, (June 1984) (with D. J. Johnstone),

"On the Relationship Between Time State Preference and Capital Asset Pricing Models," Financial Review (May 1984),

"Bid-Ask Spreads in the Market for Foreign Exchange," Journal of International Money and Finance (August 1984),

"An Economic Analysis of Hedging and The Canadian Accounting Treatment of Revenue Hedges," Canadian Journal of Administrative Sciences, (June 1987),

"The Dividend Tax Credit and Canadian Ownership Objectives," Canadian Journal of Economics (May 1987),

"A Note on the Demand for Labour and the Phillips curve Phenomenon," Journal of Economics and Business (July 1987) (with W. Y. Lee and J. Finkelstein),

"Adjustment to Production Uncertainty and the Theory of the Firm: A Note," Economic Inquiry (1988),

"The Deregulation of Canada's Financial System," Banking and Finance Law Review, (Jan 1989),

"Stock Returns and the Dollar," Canadian Investment Review, (Spring 1990), (With W. Rotenberg),

"Taxes, Funds Positioning and the Cost of Capital,' in R. Aggarwal (ed) Advances in Financial Planning and Forecasting, JAI Press, 1990,

"Assessing Foreign Exchange Exposure: Theory and Application Using Canadian Firms," Journal of International Financial Management and Accounting (Spring 1990) (With W. Rotenberg),

"Research in Finance at Canadian Administration and Management Faculties," Canadian Journal of Administrative Studies, (With F. Heath), (December 1990), "The Influence of Production Technology on Risk and the Cost of Capital," Journal of Financial and Quantitative Analysis (March 1991),

"Evidence on Corporate Preferences For Foreign Currency Accounting Standards", Journal of International Financial Management and Accounting, (with W. Rotenberg) (Summer 1991)),

"Peoples Acquisition of Zale: An application of Valuation Principles," in Canadian Investment Banking Review, (R. Rupert, Editor), McGraw-Hill Ryerson, 1992,

"The Cost of Equity Capital of a Non-Traded Unique Entity," Canadian Journal of Administrative Sciences, (June 1993),

"Lessons From Canadian Capital Market History," Canadian Investment Review (Spring 1995),

"Making Capital Budgeting Decisions in Multinational Corporations," Managerial Finance 22-1, (1996),

"Great Lakes Forest Products" Accounting Education 5 (Winter 1996) (with Professor W. Rotenberg),

"On the Nature of Foreign Exchange Exposure" Journal of Multinational Financial Management" (Spring 1996),

"The Importance of Market to Book Ratios in Regulation," Quarterly Bulletin, National Regulatory Research Institute, Winter 1997,

"A New Model for Estimating Risk Premiums (Along with Evidence of their Decline)" Journal of Applied Corporate Finance, (Spring 1998),

"The Case Against Foreign Bonds in Canadian Fixed Income Portfolios," Canadian Investment Review, (Spring 1998),

"The CAPM, Equity Risk Premiums and the Privately Held Business," Journal of Business Valuation (1999),

"Estimating the Equity Risk Premium and Equity Costs: New Ways of Looking at Old Data," Journal of Applied Corporate Finance, (Spring 1999), "Time to Pass the Old Maid," Canadian Investment Review, (Spring 1999),

"Risk and Return in Capital Markets," Canadian Treasurer 16-2, March 2000,

"What Drives Shareholder value," Canadian Treasurer 16-3, June 2000.

"Capital Structures in Developing Countries," Journal of Finance 61-1 (March 2001, pp 87-130) (with V. Aivazian, V. Maxsimovic and A. Demirgic Kunt), (abstracted in the CFA Digest-31 -3 August 2001)

"Discounting Expected Values with Parameter Uncertainty," Journal of Corporate Finance 9- 2 (Spring 2003, pp 505-519)

"Equity Risk Premiums in the US and Canada," Canadian Investment Review (Spring 2001),

"Financial Planning with Risk," Canadian Journal of Financial Planning (December 2001),

"How to Find Value when None Exists: Pitfalls in Using APV and FTE," Journal of Applied Corporate Finance (Spring 2002),

"Do Emerging Market Firms Follow Different Dividend Policies than Firms in the US: Evidence From Firms in 8 Emerging Markets," Journal of Financial Research 26-3, (September 2003, pp 371-387) (Abstracted in CFA Digest 34-1, Feb 2004) (With V. Aivazian and S. Cleary),

"Dividend Policy and the Organisation of Capital Markets, Journal of Multinational Financial Management, 13-2 (April 2003, pp 101-121 (With V. Aivazian and S. Cleary),

"What to do with Executive Stock Options," Canadian Investment Review 16-2, (Summer 2003, pp 12-18),

"Formulating Retirement Targets and the Impact of Time Horizon on Asset Allocation," Financial Services Review 13-1, (Spring 2004),

"Dividend Policy and the Role of the Contracting Environment," FSR Forum, December 2005, pp 13-22, "Dividend Smoothing and Debt Ratings," Journal of Financial and Quantitative Analysis, with V. Aivazian and S. Cleary (June 2006),

"Capital Cash Flows, APV and Valuation," European Financial Management, (Spring 2007).

"What Drives Provincial-Canada Yield Spreads" Canadian Journal of Economics, (Summer 2007) with Walid Hejazi and George Georgoplous.

"Cash Flow Volatility, Financial Slack and Investment Decisions," China Finance Review 2-1, (January 2008) with Sean Cleary,

"Capital market Developments in the Post 1987 Period: A Canadian Perspective," Review of Accounting and Finance 8-2, 2009, with Sean Cleary.

"Collateral Damage," 2008, Canadian Investment Review 21-4, pp 10-17.

"The Secret of Canadian Banking: Common sense?" World Economics, September 2009

"Information Asymmetry, Dividend Status and SEO Announcement Day Returns" (with Bin Chang), Journal of Financial Research, (Spring 2011)

"Target Date Funds: Good News and Bad News," (with Bin Chang) Journal of Risk, Spring 2011, pp 1-28.

"The Influence of productivity growth on Equity market performance, Journal of Wealth Management (with Bin Chang, Walid Hejazi and Pauline Shum) (forthcoming)

"Asset Allocation and the Performance of American Target Date Funds," Rotman International Journal of Pension Management, (With Bin Chang) Fall 2011.

NON-JOURNAL PUBLICATIONS: "Financial Considerations for Providing Incentives for Private Industry and their Implications for Employment Level and Stability," (with M. J. Gordon) Technical study #2, Labour Market Development Task Force, Ministry of Supply and Services Canada, 1982.

"A Comparison of the Car Insurance Industry in Ontario with The Public Monopolies in Saskatchewan, Manitoba and British Columbia," 122 pp, in C. Osbourne (ed) Report of the Inquiry into Motor Vehicle Accident Compensation in Ontario, Ontario 1988.

"Securities Market Regulation: Institutional Ownership and Diversification;" "TSE Listing Proposals for Junior Companies," and "Discount Brokerage and the Entry of Financial Institutions." Reports submitted to the Ontario Securities Commission, July 1982, June 1983 and December 1983.

"Bank Profitability, Is It Excessive? (With M. Jensen and S. Klein), Report to the House Standing Committee on Finance, Trade and Economic Affairs, May 1982.

"Survey of Foreign Bank Affiliates," Chapter 8 in Small Business Financing and Non-Bank Financial Intermediaries, Facsym 1981.

"A Methodological Error in the Application of the Capital Asset Pricing Model" Proceedings ASAC, (May 1981).

International Business, (with A. Rugman and D. Lecraw), McGraw Hill, 1985.

"Hedging Foreign Exchange Exposure," in Rugman (ed), International Business in Canada: Strategies for Management, Prentice-Hall, 1988.

"Section 1650 of the CICA Handbook: Interpreting Foreign Results Under a Flexible Accounting Standard," (With W. Rotenberg), CGA Communications, 1989.

"Liability Management in the Public Sector," Report for Ministry of Treasury and Economics, May 1990 (with P. Halpern,)

"The Tax Deductibility of Interest and Hostile Takeovers," John Deutsch Institute, May 1990.

"Regulation of Transmission and Distribution Activities of Ontario Hydro," in R. Daniels, Editor, Ontario Hydro at the Millenium: Has Monopoly=s Moment Passed? McGill-Queens University Press Fall 1996 (with P. Halpern).

"Competition and Profitability in the Financial Services Industry in Canada," in J. Mintz & J. Pesando (editors) Putting Consumers First C.D Howe Institute, 1996.

"What Drives Shareholder Value," Financial Intelligence IV-6, Federated Press , Spring 1999.

"Canada's Competitiveness over the last 20 years," Rotman Management, Spring/Summer 1999.

"A Walk through Risk and Return," Advisor's Guide to Financial Research, 1999.

"Picking the Right Stocks," Advisor's Guide to International Financial Research, 2000.

"The CAPM, Equity Risk Premiums and the Privately Held Business," reprinted in W. Albo et al, Purchase and Sale of Privately Held Businesses, CA Press, Toronto, Ontario, 2000

"Investments, Alternative Investments and Bubbles," in Advisor's Guide to New Investment Opportunities, 2001.

"The Increasing Complexity of Bank Brands," Rotman Management, Spring/Summer 2001.

"Asset Allocation in the Long Run," Advisor's Guide to Risk Management, 2002.

"The Competitiveness of Corporate Canada," Financial Post, July 2002.

"Corporate Responsibility," Rotman Management, Spring/Summer 2003.

"The MBA International Finance course: a course whose time has come and gone, in A. Rugman (editor) Research in Global Strategic Management, JAI press, June 2003.

"The fundamentals of finance all business professionals should know and remember," Inside the Minds: Textbook Finance, Aspatore Books, June 2003.

"Anticipating the Big Boom," Rotman, the magazine of the Rotman School of Management, Fall 2005.

"Asset Allocation: The Long View," in H. Evensky (Editor) Retirement Income Redesigned: Master Plans for Distribution, Bloomberg Press, Princeton, 2006.

"Loyalty in Finance," Rotman, the magazine of the Rotman School of Management, Fall 2006.

Introduction to Corporate Finance, John Wiley and Sons, 2007 (with Sean Cleary)

"Saving Capitalism from the Capitalists," Rotman, the magazine of the Rotman School of Management, Summer 2008.

"An Overview of Value Based Management," in Advanced Corporate Finance, C. Krishnamurti and S.R. Vishwanath Prentice Hall International, 2009.

Introduction to Corporate Finance, John Wiley and Sons, (2nd edition) 2010 (with Sean Cleary)

"The Cost of Equity Capital and Fair Rate of Return on Equity (ROE) for a Canadian Utility" Canadian Regulation, Gordon Kaiser (Editor) 2011.

TESTIMONY

Expert financial witness (individually & with the late Professor M.K. Berkowitz) in rate hearings for Altalink partners, ATCO Gas (South), ATCO Pipelines (South), ATCO Electric, Bell Canada, Consumers Gas, Teleglobe, Maritime T&T, Island Tel, BC Tel, AGT, Newfoundland Tel, Union Gas, Ontario Hydro, Centra Gas Ontario, NB Tel, Northwestel, Pacific Northern Gas, BC Gas, West Kootenay Power, TransCanada Pipelines, TransEnergie, Trans Mountain Pipelines, IPL, Westcoast Energy, Nova Gas Transmission, Foothills Pipeline, TQ&M, ANG, and Centra Gas Manitoba.

Other civil cases include: prudent investments in a money market fund; the use of inverse floaters; the valuation of a brick company; the purchase of a private company by a Crown corporation; the liability of an investment dealer in a deficient private offering memorandum; the role of the Crown in managing moneys placed "in trust," the motivation for differential investment decisions, the materiality of press releases and the role of event clauses in contracting.

Ph.D SUPERVISOR:

George Pink, A Dominance Analysis of Canadian Mutual Funds, 1988,

Greg Lypny, An Experimental Study of Managerial Pay and Firm Hedging Decisions, 1989,

Frank Skinner, Credit Quality Adjustments and Corporate Bond Yields, 1990,

Rui Pan, Probability Analysis of Option Strategies, 1994,

Peter Klein, Three Essays on the Capital Gains Lock-in Effect, 1996,

Guy Bellemare, Capital Market Segmentation: US -Canada, 1996,

Kevin Lam, The Pricing of Audit Services, 1997,

Sean Cleary, The Relation Between Firm Investment and Financial Slack, 1998,

Xinlei Zhao, Three Essays on Financial Markets, 2002,

Lynnette Purda, Elements of Corporate Debt Policy, 2003,

Themis Pantos,. Investment Distortions in the Presence of a Sovereign Debt Overhang, 2003.

Zhao Sun, PEG ratios and Stock Returns, 2004.

Zhaoxia Xu, Dynamic Adjustment of Financial Policy, 2007

Bin Chang, Information in Financial Markets, 2008

Ambrus Kesckes, Three Essays on IPOs, 2008 (Co-chair with Jan Mahrt-Smith)

Jun Zhou, Industry Influences on Corporate Financial Policy, 2010.

CASE WRITING:

A fair rate of return for Bell Canada, 1986.
Canvend 1984, A & B, 1988.
Peoples Jewellers, 1988.
Great Lakes Forest Products A, 1989.
Inco, 1989.

Peoples acquisition of Zale, 1990.
American Can Canada, 1990.
Great Lakes Forest Products A, 1993 (with W. Rotenberg)
BC Telephone, 1993
103 Kirsten Avenue, 1994
Great Lakes Forest Products B, 1994 (with W. Rotenberg)
Mill Creek Jewellery,1995 (With E. Kirzner)
Chapters, draft 2002.
Second Cup Valuation, draft 2002.

SERVICE:

Executive Committee: 1980-2, 1989-90, 1993-4, 2001-3, 2009-10
Finance Area Co-ordinator 1987-91, 1994-2008
External Advisory Board, Health Administration Faculty, 1985-92.
Editorial Board Activities:

- Journal of Economics & Business 1982-87.
- Finance Section Editor, Canadian Journal of Administrative Sciences 1993-2005.
- Journal of Multinational Financial Management 1989-.
- Journal of International Business Studies 1992-
- Associate Editor, Multinational Finance Journal, 1995-
- Journal of Applied Finance 2003-2007

Director at large Multinational Finance Society 1998-
Co-Chair 1991 Northern Finance Association meetings.
Chair 1998 Northern Finance Association meetings
Chair 2008 MFS annual meetings.
President Multinational Finance Society, 2010-11
Programme Committee member FMA meetings, October 1993.
Programme Committee member SFA meetings November 2002.
Programme Committee member, MFS meetings 2002-10
Programme Committee Member, Global Finance Conference, 2006.
Programme Committee Member, European Financial Management 2006-2010
Programme Committee member, NFA meetings 2008-
Investments Committee, Trinity College, U of T.
Pension Committee, Governing Council University of Toronto, 2011
Special committee on the Supplementary Retirement Arrangement (SRA) University of Toronto, 2011
Frequent media commentator.

February 2012

TAB 18

PETER C.P. THOMPSON, Q.C.
T 613.787.3528
pthompson@blg.com

Borden Ladner Gervais LLP
World Exchange Plaza
100 Queen St. Suite 1100
Ottawa, ON, Canada K1P 1J9
T 613.237.5160
F 613.230.8842
F 613.787.3558 (IP)
blg.com

Borden Ladner Gervais

By email

November 15, 2012

Fred Cass
Aird & Berlis LLP
Brookfield Place, 181 Bay Street
Suite 1800, Box 754
Toronto, ON M5J 2T9

Dear Mr. Cass,

Enbridge Gas Distribution Inc. ("EGD") 2013 Rates	
Board File No.:	**EB-2011-0354**
Our File No.:	**339583-000132**

We are writing in connection with the pending appearance on Monday, November 19, 2012, of the Company witness panel that will be providing evidence relevant to the unresolved Equity Ratio issue.

A portion of the examination that we are planning to conduct of that witness panel relates to the information contained in Exhibit I, Issue E1, Schedule 21.2, subparagraph (f). In that Interrogatory Response, EGD was supposed to provide a list of all of its financings since January 1, 2007, and the costs thereof. The response lists all "outstanding public term debt financing.". It is unclear whether some or all of these financings were made after January 1, 2007.

During our examination of the witnesses, we will be asking that this information be supplemented to show the date that each of the financings were placed. We will also be requesting that the information be updated to reflect any financings placed since August of 2012.

We also plan to ask the witnesses to obtain and produce information that shows the extent to which the rates EGD has paid for its actual financings since January 1, 2007, compares to the actual rates paid for financings since January 1, 2007, by entities to which EGD says it should be compared.

So as to dispense with the need for an undertaking at the hearing, we respectfully request that you have the witnesses who will be appearing on EGD's first panel obtain and bring to the hearing information pertaining to the actual financings since January 1, 2007, placed by the entities to which EGD says it should be compared, including ATCO, Fortis, GazMétro, Nova Scotia Power and Union Gas Limited.

We wish to see how the actual rates paid by each of those entities for financings since January 1, 2007, compare to the rates paid by EGD for reasonably contemporaneous financings. The question is whether EGD's actual costs of these financings are lower or about the same as the actual costs of contemporaneous financings placed by the allegedly comparable entities.

Please call me if you have any questions about the nature of the information we are requesting that the witnesses have available by Monday next.

Yours very truly,

Peter C. P. Thompson, Q.C.

PCT\slc

c. Norm Ryckman (EGD)
Robert Bourke (EGD)
Intervenors EB-2011-0354
Paul Clipsham (CME)

OTT01: 5369158: v1