500 Consumers Road
North York ,ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Bonnie Jean Adams
Regualtory Coordinator, Regulatory Affairs
Tel 416-495-5499
Fax 416-495-6072
Email: EGDRegulatoryProceedings@enbridge.com

November 12, 2010

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
2011 Rate Adjustment Application
Ontario Energy Board ("Board") File Number EB-2010-0146

In accordance with the Board's Procedural Order No. 1, dated October 15, 2010, enclosed please find the interrogatory responses of Enbridge for the above noted proceeding.

Also included in the package, please find the following update / new evidence:

- Updated Exhibit A, Tab 1, Schedule 1, and
- Exhibit A, Tab 4, Schedule 2

The evidence as been filed through the Board's Regulatory Electronic Submission System (RESS) and will be available on the Enbridge website at www.enbridgegas.com/ratecase.

Two paper copies being forwarded to the Board via courier.

Please contact the undersigned if you have any questions.

Yours truly,

Bonnie Jean Adams

Bonnie Jean Adams
Regulatory Coordinator, Regulatory Affairs

cc: Mr. F. Cass, Aird & Berlis LLP (via email and courier)
All Interested Parties EB-2009-0172 (via email)

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 2 /

Please confirm that there have been no departures from the terms of the EB-2007-0615 settlement for the calculation of the 2011 revenue requirement, assignment of the revenue requirement to the rate classes, and the derivation of the 2011 rates. If there were departures, please identify and describe the nature of any departures.

RESPONSE

Confirmed.

Witnesses: K. Culbert
R. Lei
A. Kacicnik
D. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 4 /

Please provide a table of new customer additions, comparing Board-approved with actual, for each of the past 5 years. Please also include the 2011 forecast.

RESPONSE

Please see the Table 1 comparing the actual customer additions with the Board-approved in the last 5 years.

Witnesses: F. Ahmad
I. McLeod

Table 1 - New customer additions actual vs. Board-approved

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
Sector	2005 Actual	2005 Board Approved Budget	2006 Actual	2006 Board Approved Budget	2007 Actual	2007 Board Approved Budget	2008 Actual	2008 Board Approved Budget	2009 Actual	2009 Board Approved Budget	2010 Board Approved Budget	2011 Forecast
Residential												
New Construction	39,115	40,481	34,677	37,822	32,900	35,098	30,300	33,897	23,110	31,739	22,616	27,303
Replacement	8,191	7,780	8,566	8,132	7,008	8,518	7,742	7,092	6,385	6,548	7,174	6,309
Total	47,306	48,261	43,243	45,954	39,908	43,616	38,042	40,989	29,495	38,287	29,790	33,612
Apartment												
New Construction					5		22	43	66	41	19	30
Replacement					5		6	17	2	7	7	8
Total					10		28	60	68	48	26	38
Commercial												
New Construction	2,383	1,927	2,761	1,882	1,943	1,641	2,019	2,381	1,899	1,955	1,665	1,762
Replacement	995	892	1,582	1,147	1,050	948	957	1,086	621	941	888	821
Total	3,378	2,819	4,343	3,029	2,993	2,589	2,976	3,467	2,520	2,896	2,553	2,583
Industrial												
New Construction	11	12	26	18	6	16	5	13	5	8	7	3
Replacement	2	12	10	10	3	7	1	5	1	2	3	1
Total	13	24	36	28	9	23	6	18	6	10	10	4
Total Customer Additions	50,697	51,104	47,622	49,011	42,920	46,228	41,052	44,534	32,089	41,241	32,379	36,237

Witnesses: F. Ahmad
I. McLeod

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: Ex. B /Tab 1/ Sch 5/

a. Please provide a table of historic and forecast gas volumes, in a similar format to the example shown below, broken down by general service and contract that shows the Board-approved versus the actual volumes for the 5-year period 2006 through 2010 (as available). Please also include the 2011 forecast. Additionally, please include the average number of customers.

	Year 1		Year 2		Year 3, etc.	
	Board-approved	Actual	Board-approved	Actual	Board-approved	Actual
General Service						
Contract						
Total Volume						
No. Customers (avg.)						

b. Please also provide a table similar to part a. above showing weather-normalized volumes.

RESPONSE

a) Table 1 on page 3, provides the requested information for un-normalized volumes.

b) Table 2 on page 4, illustrates the requested information for weather normalized volumes. In order to compare the year over year variance between actual and Board Approved normalized numbers on the same basis, each year's actual results have been normalized to the corresponding Board Approved degree days for that year.

   During the requested time period, distribution volumes were influenced by many events that have had an impact on annual use.

Witness: R. Lei

Some of these events would include:

a. Fluctuations in natural gas prices;
b. Rate switching and migration between rate classes;
c. The economic downturn and extended recovery that began in the fall of 2008; and
d. Declining residential average use.

Table 1 - Weather Un-Normalized Volumes, Customers and Degree Days

(Volumes in $10^6 m^3$)

	2005		2006		2007		2008		2009		2010		2011
	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Estimate	Budget
General Service	7,963.9	7,950.4	7,932.8	7,490.5	7,642.2	8,314.8	8,288.0	8,806.0	9,083.2	9,129.2	9,083.5	9,089.9	9,283.4
Contract	4,334.2	4,215.6	4,387.9	3,996.4	4,134.3	3,758.5	3,355.2	3,101.5	2,316.6	2,205.6	2,008.6	2,061.7	2,022.9
Total Volumes	12,298.1	12,166.0	12,320.7	11,486.9	11,776.5	12,073.3	11,643.2	11,907.5	11,399.8	11,334.8	11,092.1	11,151.6	11,306.3
No. Customers (avg.)	1,718,766	1,724,716	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528	1,935,736	1,965,538

Note:
Customers and volumes were developed based upon fiscal year information up to 2005.
From 2006 onwards, they are presented on a calendar-year basis.

Table 2 - Weather Normalized Volumes and Customers

(Volumes in $10^6 m^3$)

	2005		2006		2007		2008		2009		2010		2011
	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Estimate	Budget
General Service	7,963.9	7,822.8	7,932.8	7,901.9	7,642.2	8,037.9	8,288.0	8,369.7	9,083.2	8,833.7	9,083.5	9,089.9	9,283.4
Contract	4,334.2	4,199.2	4,387.9	4,119.1	4,134.3	3,739.8	3,355.2	3,099.6	2,316.6	2,191.4	2,008.6	2,061.7	2,022.9
Total Volumes	12,298.1	12,022.0	12,320.7	12,021.0	11,776.5	11,777.7	11,643.2	11,469.3	11,399.8	11,025.1	11,092.1	11,151.6	11,306.3
No. Customers (avg.)	1,718,766	1,724,716	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528	1,935,736	1,965,538

Note:
Customers and volumes were developed based upon fiscal year information up to 2005.
From 2006 onwards, they are presented on a calendar-year basis.

Witness: R. Lei

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: Ex. B /Tab 2/ Sch 2/ para 4

The excerpt provided from the Board's EB-2010-0175 DSM Plan Decision talks about Enbridge filing a future amendment to its 2011 DSM Plan to recognize the government's policy with respect to increased conservation programs for low income consumers. The Decision also mentions the possibility of a funding request for "additional funds for low income programs". How would any such additional funding be handled? Would the incremental funding be managed through the 2011 DSMVA?

RESPONSE

Enbridge's recently filed Amended Low Income 2011 DSM Plan includes a request for additional funding beyond the Board-approved 2011 DSM Plan budget of $26,708,068. Enbridge's proposal is that this incremental budget be assigned to the 2011 DSMVA for clearance to Rate 1 residential customers.

Please refer to Enbridge's recently filed Amended Low Income 2011 DSM Plan (EB-2010-0175, Exhibit B, Tab 2, Schedule 10, paragraphs 12 and 13) for additional details on the proposed use of the 2011 DSMVA.

Witnesses: K. Culbert
M. Sousa
P. Squires

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 2, page 3

Please confirm that the DSM budget for 2010 and 2011 are the same, at $26.7 million.

RESPONSE

The 2011 DSM budget at $26.7 million, unadjusted to account for the EB-2010-0175 DSM Plan Board Decision, is the same as the 2010 DSM budget of $26.7 million.

Witnesses: K. Culbert
A. Kacicnik
A. Mandyam

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 1, Appendix A

a) Please confirm that Enbridge has collected approximately $7.9 million through the revenue requirement in 2008 through 2010 as part of the Y-factor associated with the York Energy Centre and Greenfield South generation facilities.

b) If either or both of these projects are cancelled, would Enbridge attempt to recover its costs and the costs paid by ratepayers to date?

c) Has Enbridge received any information on the projects noted in light of the decision to cancel the construction of the planned project in Oakville and the implications for other GTA generation projects?

REPONSE

a) The sum of Y-factor power generation project revenue requirements approved for recovery in 2008 through 2010 was $6.7 million. The amounts never included any costs or related revenue requirement associated with the York Energy Centre or Greenfield South facilities. As stated in written evidence at Exhibit B, Tab 2, Schedule 1, the York Energy and Greenfield South projects are not scheduled to come on line before the end of 2011 and therefore do not contribute to the revenue requirement calculated for 2011 either.

b) As indicated above, these power generation projects have not been included within any revenue requirement determination to date. Further, should projects be cancelled, Enbridge expects to recover costs incurred through Contribution in Aid of Construction and / or financial assurances (such as irrevocable letters of credit) provided to Enbridge by the project proponents. Hence, a potential cancellation of the projects is not expected to have cost consequences for other ratepayers or Enbridge.

c) Enbridge has not received any determinative information in light of the noted decision.

Witnesses: K. Culbert
S. Murray
J. Sim

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 2

a) Please explain why any LEAP funding determined as 0.12% of the distribution revenue requirement would be included as a DSM cost.

b) Please provide the estimated cost of LEAP assuming the 0.12% of the distribution revenue requirement is put in place for the 2011 rate year. Please also provide the amount that EGD will be required to contribute to the Winter Warmth program as per its court settlement.

c) Please confirm that there were no costs related to assistance for customers, such as a Winter Warmth fund or similar funds, included in the approved revenue requirement in EGD's last cost of service proceeding. If this cannot be confirmed, please indicate the amount that was included.

d) How have the Class Action Suit costs been allocated between customer classes for 2011?

e) The October 20, 2010 letter from the Board re LEAP Emergency Financial Assistance indicates at Attachment A that the Board has determined that the LEAP funding should be recovered from all rate classes, based on distribution revenue by rate class. If the response to part (d) is not consistent with this allocation of costs please provide a table that shows the current allocation of the late payment penalty litigation costs to the rate classes with an allocation that is based on distribution revenues.

f) If the response in (d) above is not consistent with the allocation in the October 20, 2010 letter, please explain if EGD proposes to change the allocation of the class action suit costs to conform with the Board letter. If not, please explain why not.

REPONSE

a) Before the issuance of the LEAP program manual and the October 20, 2010, Ontario Energy Board LEAP letter, there was uncertainty as to an eventual direction in relation to potential LEAP treatments / requirements. It is now apparent that the

Witnesses: J. Collier
K. Culbert
A. Kacicnik
A. Mandyam
M. Sousa
M. Suarez

LEAP program is to be considered outside of any DSM related low income programs.

b) The estimated cost of LEAP is $1.2 million. (0.12% of the $988.6 million 2011 distribution revenue as shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 24). Enbridge anticipates having to contribute approximately $0.5 to $0.6 million to achieve the $1.2 million indicated LEAP funding.

c) Confirmed.

d) The Class Action Suit Deferral Account ("CASDA") balance for each installment over the 5-year disposition period is allocated on the basis of the number of customers in each rate class. This methodology was approved by the Board in the CASDA Proceeding, EB-2007-0731.

e) Applying the two allocation methods to the CASDA annual installment results in the following distributions by rate class:

Allocation of CASDA Annual Installment

	Based on 2011 # of Customers		Based on 2011 Distribution Rev. Req't	
Rate 1	$	4,735.96	$	3,508.67
Rate 6	$	422.17	$	1,452.94
Rate 9	$	0.03	$	0.86
Rate 100	$	-	$	0.00
Rate 110	$	0.54	$	52.02
Rate 115	$	0.09	$	29.02
Rate 125	$	0.01	$	38.45
Rate 135	$	0.09	$	3.62
Rate 145	$	0.49	$	32.37
Rate 170	$	0.10	$	25.58
Rate 200	$	0.00	$	13.54
Rate 300	$	0.02	$	2.44
TOTAL	$	5,159.50	$	5,159.50

f) Enbridge does not propose to change its allocation of the CASDA balance. As Enbridge contributions to the Winter Warmth fund are donations which are not included within CASDA nor Enbridge's base year or ongoing incentive regulation revenue requirement (i.e., there is no cost allocation requirement as these amounts do not impact ratepayers), it is appropriate to continue with the current methodology for allocating the CASDA balance.

Witnesses: J. Collier
K. Culbert
A. Kacicnik
A. Mandyam
M. Sousa
M. Suarez

DIRECT ENERGY INTERROGATORY #1

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 1, Appendix A, Page 1 of 1; Derivation of Proposed Direct Purchase Administration Charge (DPAC)

a. Please provide the detail of all inputs used to arrive at the proposed $2.7 Million in 2011 DPAC costs, and provide the same detailed year over year comparison for the years 2008, 2009, and 2010.

b. Please provide the same detail and year over year comparisons as noted above for system gas management costs.

c. Please provide the current list of services recovered by DPAC fees.

d. Please describe the primary cost drivers in delivering DPAC services.

e. Please describe any initiatives the Company has taken to reduce the costs associated with DPAC services.

REPONSE

a) Direct Purchase incremental costs for 2008 and 2009 were maintained for rate-setting purposes at the $1.56 million level that was agreed to in the EB-2005-0001 Settlement Agreement. Subsequent to the Ontario Energy Board's (the "Board') decision in the QRAM Generic Proceeding (EB-2008-0106), Direct Purchase incremental costs were updated for 2010 and 2011 in the respective rate adjustment applications; the proposed direct purchase incremental costs for 2011 are $2.87 million.

Witnesses: J. Collier
A. Kacicnik
M. Suarez
B. Vari
I. Macpherson

Direct Purchase Incremental Costs	2011	2010	2008-09*
Contract Management	1,420,280	1,496,799	702,456
Nominations	305,030	264,203	428,833
Invoicing & Payment Processing	81,648	72,519	24,163
Demand Forecasting & Supply Planning	38,898	39,028	0
Direct Purchase Billing Adjustments	102,947	77,196	0
Total incremental costs for activities	1,948,803	1,949,745	1,155,453
Employee benefits for labour component of incremental costs	921,128	877,859	404,547
TOTAL Direct Purchase Incremental Cost	2,869,931	2,827,604	1,560,000

** 2008-09 Based on the Settlement Agreement from EB-2005-0001.*
Cost categories are not completely comparable with current categories and cost levels have been maintained from 2006.

b) System Gas incremental costs for 2008 and 2009 were maintained for rate-setting purposes at the $0.88 million level that was agreed to in the EB-2005-0001 Settlement Agreement. Subsequent to the Board's decision in the QRAM Generic Proceeding (EB-2008-0106), System Gas incremental costs were updated for 2010 and 2011 in the respective rate adjustment applications. Proposed system gas incremental costs for 2011 are $1.38 million.

Witnesses: J. Collier
A. Kacicnik
M. Suarez
B. Vari
I. Macpherson

System Gas Incremental Costs	2011	2010	2008-09*
Gas Acquisition	273,740	272,822	270,460
Contract Management	236,539	208,155	155,618
Nominations	162,750	141,597	123,444
Invoicing & Payment Processing	183,151	122,349	149,078
Demand Forecasting & Supply Planning	68,816	68,585	0
Total incremental costs for activities	924,996	813,508	698,600
Employee benefits for labour component of incremental costs	453,493	373,500	186,212
TOTAL System Gas Incremental Cost	1,378,489	1,187,008	884,812

** 2008-09 Based on the Settlement Agreement from EB-2005-0001.*
Cost categories are not completely comparable with current categories and cost levels have been maintained from 2006.

c) Direct Purchase services include the various activities pertaining to contract management, nominations, invoicing and payment processing, demand forecasting and supply planning, and direct purchase billing adjustments.

Contract Management includes activities which range from Banked Gas Account ("BGA") processing, contract compliance policy, curtailment processing & management, Agent, Broker, Marketer ("ABM") account management, and EnTRAC support. Nominations refers to scheduling and gas control activities relating to the direct purchase deliveries. Invoicing and payment processing are activities that relate to the receipt, verification, processing of invoices and payment in support of direct purchase transactions. Demand Forecasting and supply planning activities include SENDOUT modeling and supply acquisition. And finally, direct purchase billing adjustments include non-ABC processing of changes in ownership, calculation and invoicing of DPAC, call center service fees. Also included in this category are credit risk assessments.

Witnesses: J. Collier
A. Kacicnik
M. Suarez
B. Vari
I. Macpherson

d) Costs of supporting direct purchase activities are examined annually and adjusted for rate-setting purposes to reflect the current status of the direct purchase marketplace as well as other changes that may affect the level of support that is required by vendors and/or direct purchase customers. The primary cost drivers of supporting direct purchase are directly correlated with the functions and activities that are provided to vendors and direct purchase customers as detailed in part c) of this interrogatory response.

   In addition to the regular set of activities, the Company has also experienced an increased demand for analysis on customer activity and for BGA management requests from over-delivered pools. An increased level of support is also being required for vendors who have been consolidating their pools. In addition, credit risk assessment activities have increased in response to the challenges stemming from the economic downturn. As a result, the services provided for direct purchase management and the demand for services has remained high despite the decrease in the number of direct purchase customers.

e) In 2010, the Company rolled out a new tool in EnTRAC to allow customers to download their own consumption reports to enhance customer self-service. This reduced the demand for certain types of activities and reduced associated support costs. It also freed up employees' time to respond to other types of direct purchase requests as described above in part d).

   Enbridge is also working on the MDV re-establishment project which will be rolled out in June 2011. The project serves to enhance the Company's operating practice and computer systems to establish a weather-normalized MDV for general service accounts, and to recalculate MDV during the contract term so as to minimize imbalances in the BGA. The Company expects this enhancement to ultimately reduce costs associated with BGA related analysis requests and inquiries, and BGA processing.

Witnesses: J. Collier
A. Kacicnik
M. Suarez
B. Vari
I. Macpherson

FRPO INTERROGATORY #1

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 5, PG.6-9

Preamble: Enbridge has presented the significant increase in Normalized Average Use from 2006 to 2009 along with the Contract Market Unlock for the major respective sectors that make up the rate.

As a result of the significant shift from Rate 100 to Rate 6, what, if any changes in Cost Allocation has Enbridge made in creating rates during this period? Please provide the specifics on any changes.

RESPONSE

Enbridge has not made any changes to its Cost Allocation Methodology. Enbridge's Incentive Rate Mechanism allows forecasts and allocators to be updated annually. By doing so, the assignment of revenue requirement by rate class, and consequently rate impacts, remain responsive to factors such as customer growth, volumetric gain or loss, and customer migration between various rates and service offerings. No changes were made to the underlying cost allocation methodology; only the allocators have been updated.

As seen in Exhibit B, Tab 3, Schedule 10, page 8, the allocation factors have been updated to reflect 2011 customers and volumes, among other factors, as shown in Exhibit B, Tab 1, Schedule 5, page 1. This ensures that the allocation of 2011 revenue requirement as based on 2011 forecast remains current and is aligned with any changes in the demand and the number of customers in each rate class.

Witnesses: A. Kacicnik
M. Suarez

FRPO INTERROGATORY #2

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 5, PG.6-9

Preamble: Enbridge has presented the significant increase in Normalized Average Use from 2006 to 2009 along with the Contract Market Unlock for the major respective sectors that make up the rate.

As a result of this shift, does Enbridge see a need for changes in cost allocation or ratemaking in the next rebasing? If so, what is contemplated at this time?

RESPONSE

Enbridge does not see the need to change the methodology it currently applies to cost allocation and rate design as a result of changes in average uses or the change in the number of contract customers. The methodology in place enables the appropriate alignment of costs and cost-drivers through annual updates of the forecasts and allocators, effectively reflecting any changes in volumes or number of customers due to growth, average use decline or increase, customer migration or otherwise.

Please also see Enbridge's response to FRPO Interrogatory Response #1 found at Exhibit I, Tab 4, Schedule 1.

Witnesses A. Kacicnik
M. Suarez

FRPO INTERROGATORY #3

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 5, PG.6-9

Preamble: Enbridge has presented the significant increase in Normalized Average Use from 2006 to 2009 along with the Contract Market Unlock for the major respective sectors that make up the rate.

Please provide the number of customers who have committed to move from Rate 100 to Rate 6 in 2010.

RESPONSE

Table 1 on page 2 provides the total Rate 100 customers who are forecast to move to Rate 6 in 2010. Thirteen Rate 100 customers have migrated during 2010 and another eight Rate 100 customers are expected to migrate in fall of 2010.

Table 1 - Customer Migration from Rate 100 to Rate 6

1. Customers that migrated to Rate 6 in 2010

	Standard Industrial Classification Trade Group	Number of Customers
	Apartment	5
	Chemical and Chemical Products	1
	Primary Metal & Machinery	1
	Rubber Products	1
	Transportation and Storage and Utilities	1
	Transportation Equipment	2
	Wholesale & Retail Trade	1
	Wood & Furniture Industries	1
Total		13

2. Customers expected to migrate to Rate 6 in Fall 2010

	Standard Industrial Classification Trade Group	Number of Customers
	Apartment	6
	Business & Financial Service Industries	1
	Construction Industries	1
Total		8
Grand Total		21

FRPO INTERROGATORY #4

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 5, PG.6-9

Preamble: Enbridge has presented the significant increase in Normalized Average Use from 2006 to 2009 along with the Contract Market Unlock for the major respective sectors that make up the rate.

Please provide the number of customers who have committed to move from Rate 145 to Rate 6 in 2010

RESPONSE

Table 1 below provides the total Rate 145 customers who are expected to move to Rate 6 in 2010.

Table 1 - Customer Migration from Rate 145 to Rate 6

	Standard Industrial Classification Trade Group	Number of Customers
	Chemical and Chemical Products	2
	Education Services	1
	Greenhouses/Agriculture	1
Total		4

Witness: R. Lei

FRPO INTERROGATORY #5

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 5, PG.6-9

Preamble: Enbridge has presented the significant increase in Normalized Average Use from 2006 to 2009 along with the Contract Market Unlock for the major respective sectors that make up the rate.

What would the effect be on the proposed rates for the Rate 6 class if the number of customers identified in the responses to questions 4 and 5 were added to the forecasted customers and volumes in 2011.?

RESPONSE

The proposed rates for Rate 6 have already incorporated customers that are anticipated to migrate to Rate 6 in both 2010 and 2011.

Witness: R. Lei

FRPO INTERROGATORY #6

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 6

Do Enbridge's degree day models compensate for wind? If not, why not?

RESPONSE

No, Enbridge's degree day models do not compensate for wind. The degree day models were prepared in accordance with the Ontario Energy Board's decision, which did not directly address the issue of compensating for other factors such as wind.

Witnesses: I. McLeod
H. Sayyan

FRPO INTERROGATORY #7

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 6

What is the purpose of the converting the Environment Canada degree days i.e., what is being corrected or aligned in this conversion?

RESPONSE

The degree day models were prepared in accordance with the Ontario Energy Board's (the "Board') EB-2006-0034 Decision With Reasons – Phase 1 dated July 5, 2007.

The Company sets its volumes budget using Gas Supply degree days but the data supplied by Gas Supply cannot be used to conduct the Board-approved forecasting methods, such as the Energy Probe method, because the data history is not sufficiently long. Environment Canada has an adequately long data history to conduct the approved methods.

Since the Company sets its volumes budget using Gas Supply degree days but the Board-approved methods require the longer data history supplied by Environment Canada, the Environment Canada degree day results are transformed to Gas Supply degree days as outlined at EB-2010-0146, Exhibit B, Tab 1, Schedule 6, pages 7 to 10.

Witnesses: I. McLeod
H. Sayyan

FRPO INTERROGATORY #8

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 6

What has Enbridge done to test the above conversion as being a better measure for use in projecting volumes?

RESPONSE

The degree day models were prepared in accordance with the Ontario Energy Board's EB-2006-0034 Decision With Reasons – Phase 1 dated July 5, 2007. Please see FRPO Interrogatory Response #7 found at Exhibit I, Tab 4, Schedule 7, for an explanation of the conversion.

Witnesses: I. McLeod
H. Sayyan

FRPO INTERROGATORY #9

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 7, PAGE 18, para. 15

Preamble: Enbridge states: “Sharp increases can typically have two effects. Firstly, they can influence customers’ fuel use habits, for example, the lowering of thermostat settings. Secondly, price increases can factor in customers’ decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption.

How does the model compensate for the effects of falling price seen in over the last 2 years?

RESPONSE

Please see EB-2010-0146, Exhibit B, Tab 1, Schedule 7, pages 10 to 12, for detailed average use regression equations which include a price variable. In each case, the price variable coefficient is negative, meaning that for a fall / rise in natural gas prices, average use will rise / fall.

Witnesses: I. McLeod
H. Sayyan

FRPO INTERROGATORY #10

INTERROGATORY

REF: EX. B, TAB 1, SCHEDULE 7, PAGE 18, para. 15

Preamble: Enbridge states: "Sharp increases can typically have two effects. Firstly, they can influence customers' fuel use habits, for example, the lowering of thermostat settings. Secondly, price increases can factor in customers' decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption.

What has Enbridge analyzed to test the ability of the model to compensate appropriately for this effect?

RESPONSE

Please refer to EB-2010-0146, Exhibit B, Tab 1, Schedule 7, pages 10 to 12, for detailed average use regression equations. In each average use regression equation that contains a natural gas price variable, the sign of the price variable coefficient is appropriate (i.e., negative) and the variable is significant at a probability greater than 90%. This statistically significant relationship adequately captures the demand responsiveness of customers to changes in natural gas prices.

Witnesses: I. McLeod
H. Sayyan

FRPO INTERROGATORY #11

INTERROGATORY

REF: EX. B., TAB 4, SCHEDULE 1, PAGE 4, para. 10 & 11

Preamble : Enbridge states: “The Company and intervenors participated in a System Reliability consultative and hearing (EB-2010-0231). The outcome of that proceeding has been included as a component of the 2011 gas supply portfolio.

Please provide the total expected cost of the outcome of the System Reliability proceeding that is included in the 2011 forecast.

RESPONSE

The expected cost of the System Reliability outcome is a function of natural gas prices, transportation costs and basis differentials prevalent at the time when the outcome is costed.

At the time of System Reliability proceeding, the cost of the System Reliability outcome was estimated at approximately $23.2 million. The estimate was based on April 2010 QRAM natural gas prices, transportation costs and basis differential.

Based on the 2011 gas supply portfolio (which is based off the October 2010 QRAM reference price), the cost of the System Reliability outcome is estimated at approximately $16.4 million.

Witnesses: A. Kacicnik
D. Small

FRPO INTERROGATORY #12

INTERROGATORY

REF: EX. B., TAB 4, SCHEDULE 1, PAGE 4, para. 10 & 11

Preamble : Enbridge states: "The Company and intervenors participated in a System Reliability consultative and hearing (EB-2010-0231). The outcome of that proceeding has been included as a component of the 2011 gas supply portfolio.

Please provide a specific description of how the forecasted costs are included in rates including differentiation between rate classes.

RESPONSE

While the outcome of the System Reliability proceeding is reflected in the Company's 2011 gas supply portfolio, the cost consequences of the outcome are not part of the proposed 2011 rate adjustment, but will take effect in the Company's January 1, 2011 QRAM rates.

The 2011 gas supply revenues reflect the 2011 forecast of Gas Costs to Operations (at the October 1, 2010 QRAM reference price) in the amount of $1,416.30 million (Exhibit B, Tab 1, Schedule 2, page 1, Row 25, Col. 1) including changes to the Company's 2011 gas supply portfolio relative to the 2010 gas supply portfolio as well as storage and storage associated transportation costs. Changes to these elements are not captured through the Company's QRAM rate changes.

In addition, as outlined in Exhibit B, Tab 4, Schedule 1, the 2011 gas supply portfolio includes the contract changes for transportation capacity as approved in the System Reliability Decision (EB-2010-0231).

The cost consequences of these changes are not reflected in the 2011 rate adjustment but will take effect in the Company's January 1, 2011 QRAM rates. This is highlighted in the Company's pre-filed evidence at Exhibit B, Tab 3, Schedule 1, page 4. Note that this approach is consistent with the Company's QRAM methodology which adjusts rates in each quarter of a fiscal year to reflect changes in commodity and upstream transportation costs.

Witnesses: A. Kacicnik
D. Small

FRPO INTERROGATORY #13

INTERROGATORY

REF: EX. B., TAB 4, SCHEDULE 1, PAGE 4, para. 10 & 11

Preamble : Enbridge states: “The Company and intervenors participated in a System Reliability consultative and hearing (EB-2010-0231). The outcome of that proceeding has been included as a component of the 2011 gas supply portfolio.

For each of the rate classes affected, please provide a table that shows the rate affected as proposed, the quantities allocated to the rate class and what the rate would have been absent the System Reliability initiatives.

RESPONSE

As outlined in the response to FRPO Interrogatory #1 found at Exhibit I, Tab 4, Schedule 1, based on the 2011 gas supply portfolio (which is based off the October 2010 QRAM reference price), the cost of the System Reliability outcome is estimated at approx. $16.4 million.

The table below shows the allocation of $16.4 million to the customer rate classes.

	Cost Allocation of System Reliability Initiatives
	($M)
Rate 1	8.87
Rate 6	7.09
Rate 9	(0.00)
Rate 100	(0.00)
Rate 110	0.15
Rate 115	0.04
Rate 125	0.00
Rate 135	0.01
Rate 145	0.03
Rate 170	0.04
Rate 200	0.18
Rate 300	0.00
	16.40

Witnesses: A. Kacicnik
D. Small

As discussed in the response to FRPO Interrogatory #2 found at Exhibit I, Tab 4, Schedule 2, the cost consequences of the System Reliability outcome are not part of the proposed 2011 rate adjustment, but will take effect in the Company's January 1, 2011 QRAM rates (note that the cost of the System Reliability outcome within the January 2011 QRAM will be a function of natural gas prices, transportation costs and basis differentials prevalent at the time when the January 2011 QRAM application is prepared).

As an illustration, the $8.9 million in cost allocated to Rate 1 customers would represent an incremental T-service rate impact of approx. 1% (in addition to the proposed 2011 rate adjustment) for that rate class.

JUST ENERGY INTERROGATORY #1

INTERROGATORY

Reference: Ex. B, Tab 3, Sch. 1, Page 7 of 7

Enbridge has identified an increase in the incremental costs associated with the management of the Direct Purchase Administration function for 2011. Please provide all documents and rationale used in determining the proposed increase in the account charge.

REPONSE

Please see the response to Direct Energy Interrogatory #1 found at Exhibit I, Tab 3, Schedule 1, page 1, for the details that support the proposed increase in overall incremental costs for the direct purchase management function.

Enbridge is proposing to retain the monthly fixed charge at $75 per pool. The proposed monthly account charge has increased as a result of the lower projected number of accounts for 2011 compared to 2010.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

JUST ENERGY INTERROGATORY #2

INTERROGATORY

Reference: Ex. B, Tab 3, Sch. 1, Appendix A Page 1 of 1

Please provide the rationale and back-up for the projected number of pools and accounts for 2011.

REPONSE

The 2011 forecast of the number of pools and accounts is based on actual counts up to August 2010, and forecasts a subsequent net decline of 10 pools from that level. The 2011 forecast is based on observed trends and projections stemming from the addition of new vendor pools, as well as a reduction of existing pools from consolidation and customer migration.

The 2011 forecast number of accounts is based on the two-year average decline in the number of direct purchase customers in 2009 and 2010. The average decline was removed from the customer count determined in August 2010 to establish the 2011 forecast level.

Witnesses: J. Collier
A. Kacicnik
B. Vari

JUST ENERGY INTERROGATORY #3

INTERROGATORY

Please provide the annual level of Direct Purchase and System Supply customers in terms of volume and numbers for the past 3 years and estimates for the next two years.

REPONSE

Table 1 below illustrates the annual volume of Direct Purchase and System Supply customers and Table 2 illustrates the annual average of number of customers.

Table 1 - Direct Purchase and System Supply Volumes

(Volumes in $10^6 m^3$)

	2007 Actual	2008 Actual	2009 Actual	2010 Estimate	2011 Budget
System Supply	4,998.8	5,254.2	5,417.4	5,810.6	5,887.5
Direct Purchase	7,074.5	6,653.3	5,917.4	5,341.0	5,418.8
Total	12,073.3	11,907.5	11,334.8	11,151.6	11,306.3

Table 2 - Direct Purchase and System Supply Customers

	2007 Actual	2008 Actual	2009 Actual	2010 Estimate	2011 Budget
System Supply	1,117,339	1,182,328	1,248,617	1,366,243	1,387,063
Direct Purchase	707,450	682,692	638,988	569,493	578,475
Total	1,824,789	1,865,020	1,887,605	1,935,736	1,965,538

Witnesses: J. Collier
A. Kacicnik
R. Lei

TCE INTERROGATORY #1

INTERROGATORY

Reference: i) Exhibit B, Tab 2, Schedule 1, Appendix A, page 3
ii) Exhibit B, Tab 2, Schedule 1, Appendix A, page 3, line 13 and 14

Request: a) Please explain why there are no revenues listed in line 1 to 6 for the calculation of the Ontario Utility Income.
b) Please confirm that the reason for the negative income tax amounts in Reference (ii) is that the depreciation and amortization expense exceeded the taxes payable. If unable to confirm, please explain.

RESPONSE

a) As per the Company's Incentive Regulation ("IR") Settlement Agreement, Y-factors represent test year revenue requirements for gas-in-storage related carrying costs, Demand Side Management ("DSM"), Customer Care, and power generation projects. Given that the purpose of Y-factors is to determine test year revenue requirements (i.e., costs) only, there are no revenues listed in the referenced exhibit.

Revenues that need to be recovered from each rate class for services provided are derived through the cost allocation and rate design processes.

As shown in Exhibit B, Tab 1, Schedule 2, page 1, Line 26, the total 2011 revenue to be recovered from rates equals $2,404.89 million. Exhibit B, Tab 3, Schedule 5, page 1, Line 16, Column 4, outlines the 2011 revenue recovery by rate class which also equals $2,404.89 million. In other words, there is a complete match between the total revenue requirement and the rate design revenues.

b) The negative income tax amounts shown are not a result of depreciation and amortization exceeding taxes payable. The level of negative taxes shown, as explained in part a) above, is primarily as a result of the calculations being purely from a cost perspective.

Witnesses: K. Culbert
S. Murray
J. Sim

TCE INTERROGATORY #2

INTERROGATORY

Reference: i) Exhibit B, Tab 1, Schedule 2, page 1, line 26
ii) Exhibit B, Tab 3, Schedule 3, page 1, line 16, Col 5
iii) Exhibit B Tab 3, Schedule 5, page 1, Col 3

Request: a) Please reconcile the 2011 Total Revenue amount of 2,404.89 in Reference (i) with the Total Revenue Requirement amount of 2,406.016 in Reference (ii).
b) Please explain unbilled revenue and its treatment.

RESPONSE

a) and b)

As shown in Exhibit B, Tab 1, Schedule 2, page 1, Line 26, the Total 2011 Revenue to be recovered from rates equals $2,404.89 million.

Exhibit B, Tab 3, Schedule 5, page 1, Line 16, Column 4 outlines the 2011 revenue recovery by rate class that equals $2,404.89 million and which includes the sum of billed and unbilled revenue.

Therefore, there is a complete match between the total revenue requirement as outlined in Exhibit B, Tab 1, Schedule 2, page 1, and the rate design revenues as per Exhibit B, Tab 3, Schedule 5, page 1.

The $2,406,016 million as outlined in Exhibit B, Tab 3, Schedule 3, page 1, Line 16, Column 5, represents the forecast level of revenue to be recovered based on billed volumes (i.e., prior to the unbilled volumes). The Company designs rates to recover the total revenue requirement based on calendar year volumes which is the sum of billed and unbilled volumes. The amount of unbilled revenue is determined by measuring the change in unbilled revenue generated from rates applied to the December 2010 unbilled forecast of volumes and customer numbers relative to the revenues generated from the rates applied to the December 2011 unbilled forecast of volumes and customer numbers. The 2011 forecast level of unbilled revenue is depicted in Exhibit B, Tab 3, Schedule 5, page 1, Column 3. The unbilled revenue depicted in Column 3 combined with the billed revenue depicted in Column 2 equals the total revenue to be recovered from rates which is depicted in Column 4.

Witnesses: J. Collier
K. Culbert
A. Kacicnik
R. Lei
M. Suarez

TCE INTERROGATORY #3

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 8, page 5

Request: Please provide the derivation of the 80 056 10^3m^3 and explain what it represents.

RESPONSE

The 80,056 10^3m^3 represents the 2011 forecast level of contract demand for all Rate 125 customers multiplied by 12. The Rate 125 contract demand charge is applied to customers' monthly contract demand and recovers the cost of providing distribution service.

Witnesses: J. Collier
A. Kacicnik
R. Lei

TCE INTERROGATORY #4

INTERROGATORY

Reference: i) Exhibit B, Tab 3, Schedule 1, page 6, paragraphs 19 and 20
ii) Exhibit B, Tab 3, Schedule 10, pages 8 and 9

Request: a) Please explain how the allocators referred to in Reference (i) are calculated
b) Please explain the relationship between the allocators and the figures presented in Reference (ii).

RESPONSE

a) The allocators referred to in Exhibit B, Tab 3, Schedule 1, page 6, Paragraph 19 (reference i) are itemized in detail in Exhibit B, Tab 3, Schedule 10, page 8 (reference ii).

Allocators in lines 1.1 to 1.4 in reference (ii) represent the 2011 volumetric forecasts by rate class for Sales Service, Annual Deliveries, and Bundled Transportation deliveries.

Allocators in lines 2.1 to 2.4 are calculated on the basis of rate class contributions to peak demand.

Allocators in lines 3.1 and 3.2 are a function of average annual demand, average winter demand, and peak demand. The space allocator is derived by calculating the excess of average winter demand over average annual demand by rate class. The deliverability allocator is derived by calculating the excess of peak over average winter demand by rate class.

Allocators in lines 4.1 and 4.2 are the 2011 projected number of customers by rate class, and the net capital cost of services by rate class.

b) The allocators referenced in Exhibit B, Tab 3, Schedule 1, page 6, Paragraph 19 are the same allocators provided in Exhibit B, Tab 3, Schedule 10, pages 8 and 9. While page 8 shows the factors in their respective units (e.g. m^3, number of customers), page 9 is the percentage allocation using the factor units.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

TCE INTERROGATORY #5

INTERROGATORY

Reference: i) Exhibit B, Tab 3, Schedule 10, page 2, line 4, Col 1
ii) Exhibit B, Tab 1, Schedule 2, page 1

Request: Please reconcile the 2011 revenue requirement (excluding Gas Supply Commodity) of 1,498.89 in Reference (i) with the dollar amounts in Reference (ii)

RESPONSE

The 2011 revenue requirement of $1,498.89 million represents the 2011 total revenue from reference (ii) of $2,404.89 million less the $906 million in commodity costs from Exhibit B, Tab 3, Schedule 10, page 3, Item 1, Column 3.

The reconciliation is as follows:

	($M)
2011 Total Revenue	2,404.89
Less: Product costs	906.00
	1,498.89

Witnesses: K. Culbert
A. Kacicnik
R. Lei
M. Suarez

TCE INTERROGATORY #6

INTERROGATORY

Reference: i) Exhibit B, Tab 3, Schedule 10, page 3, line total, Col 3
ii) Exhibit B, Tab 1, Schedule 2, page 1

Request: Please reconcile the Total 2011 Revenue Requirement of 2,403.3 in Reference (i) with the dollar amounts in Reference (ii).

RESPONSE

The Total 2011 Revenue Requirement from Exhibit B, Tab 3, Schedule 10, page 3, Line Total, Column 3 excludes the revenue requirement associated with the provision of ex-franchise storage services that is recovered through Rates 325 and 330. These costs can be found at Exhibit B, Tab 3, Schedule 10, page 1, Item 4, Column 14.

The reconciliation is as follows:

	($M)
2011 Revenue Requirement (Exhibit B, Tab 3 Schedule 10, page 3)	2,403.30
Plus: Rate 325 & 330 Revenue Requirement (Exhibit B , Tab 1 ,Schedule 10, page 1)	1.60*
2011 Total Revenue (Exhibit B , Tab 1, Schedule 2, page 1)	2,404.89

*Note: The $1.6 million consists of $1.35 million in DRR and $0.25 million in LUF costs.

Witnesses: K. Culbert
A. Kacicnik
R. Lei
M. Suarez

TCE INTERROGATORY #7

INTERROGATORY

Reference: i) Exhibit B, Tab 3, Schedule 10, pages 5 and 7
ii) Exhibit B, Tab 1, Schedule 2, page 1

Request: Please reconcile the 2011 Distribution Revenue Requirement amount of 987.2 in Reference (i) with the dollar amounts in Reference (ii).

RESPONSE

The 2011 Distribution Revenue Requirement ("DRR") referenced in Exhibit B, Tab 3, Schedule 10, pages 5 and 7, excludes the revenue requirement associated with the provision of ex-franchise storage services that is recovered through Rates 325 and 330.

The reconciliation is as follows:

	($M)
2011 DRR (Exhibit B, Tab 3 Schedule 10, page 5)	987.24
Plus: Rate 325 & 330 DRR excluding LUF	1.35
2011 Total Distribution Revenue (Exhibit B ,Tab1, Schedule 2, page1)	988.59

Witnesses: K. Culbert
A. Kacicnik
R. Lei
M. Suarez

TCE INTERROGATORY #8

INTERROGATORY

Reference: Exhibit B, Tab 3, Schedule 2, rate 125, page 1

Preamble: Unaccounted For Gas Percentage

Request: Please explain how revenues and/or costs from this element are treated.

RESPONSE

The Rate 125 charges exclude the cost of unaccounted for gas. Therefore, the customer is not charged for this item in their Rate 125 charges. The unaccounted for gas percentage of 0.3% as depicted in page 1 of the Rate 125 rate schedule at Exhibit B, Tab 3, Schedule 2, page 19, represents the additional volume of gas an unbundled customer needs to deliver to Enbridge to compensate for gas which will be lost on Enbridge's distribution system.

Also note that Enbridge's bundled customers pay the cost of unaccounted for gas in their delivery charges, while unbundled customers (Rate 125 and 300) deliver unaccounted for volume to the system in-kind. In other words, to consume 100 units of volume at the end use location, an unbundled customer needs to deliver 100.3 units of volume to the Enbridge system.

Witnesses: J. Collier
A. Kacicnik
D. Small

VECC INTERROGATORY #1

INTERROGATORY

No Reference

a) Is EGDI planning to file an application regarding Earnings Sharing for 2010? Provide details-timing ,issues etc

RESPONSE

a) Yes. Enbridge, annually within the term of the approved Incentive Regulation methodology, will file an Earnings Sharing Calculation, and Deferral and Variance account review application as soon as reasonably possible after the public release of year-end financial results.

   This is in compliance with the description of Issue 11.1 in the EB-2007-0615 Board Approved Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, pages 28 and 29 (filed for reference in this proceeding at Exhibit E3, Tab 1, Schedule 1).

VECC INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B Tab 1 Schedule 3 Page 2 Table 1

a) Provide the 2010 Q3 and Annualized Inflation Growth Rates

b) Compare these to the values in Table 1

c) Discuss how timing of the IRM adjustment can/should affect the estimate of the Inflation factor

RESPONSE

a) Statistics Canada has not yet released an update to the GDP IPI FDD data series which includes 2010 Q3 results. Consequently, this request cannot be fulfilled.

b) Please see the Company’s response to question a).

c) If the timing of the IRM adjustment takes place during a period of relatively low inflation, as measured by the Canadian GDP IPI FDD, a relatively low estimate will prevail. Conversely, if the timing of the IRM adjustment takes place during a period of relatively high inflation, a relatively high estimate will prevail.

   However, the establishment of the GDP IPI FDD (including the timing of the data to be used) is stipulated in paragraph 2.1.1 of the IR Settlement Agreement which is filed in this proceeding at Exhibit B, Tab 1, Schedule 3.

Witness: I. McLeod

VECC INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B Tab 1 Schedule 4 ; Exhibit B Tab 1 Schedule 5 Appendix B

a) Does EGD now have a econometric model to forecast residential customer additions?

b) If so
   i. provide details of the inputs ,dependent and independent variables coefficients etc
   ii. Show how the model was used to forecast the 2011 additions

c) If not provide a schedule that lists the sources of all significant inputs used by EGD to prepare the "grassroots forecast, including employment, housing starts etc.

d) Provide an update/comparison of YTD 2010 customer additions compared to last years' Board Approved in Table 2 Column 3

e) Provide an estimate the revenue requirement of impact of a 1% change in the residential customer additions forecast for 2011

f) Provide and compare the latest 2010 housing start forecast in column 7 of Table 1

g) Provide the latest 2011 forecast housing start data from EGDs sources and provide a comparison the Data in Table 1.Column 8

RESPONSE

a) The Company does not use an econometric model to forecast residential customer additions. The customer additions forecasting process is a bottom up forecast meaning the forecast is developed by the sales team using inputs from builders, economic information/trends and professional judgment and informed opinion.

Witnesses: I. McLeod
F. Ahmad

Please refer to Exhibit B, Tab 1, Schedule 4, paragraph 2, for an explanation of the Company's customer additions forecasting process.

b) i) Please see the Company's response to question a).

ii) Please see the Company's response to question a).

c) Please see below, the economic data and the source of each data series which is considered during the Company's residential customer additions forecasting process.

Residential Customer Additions Variable Input Schedule

Col. 1 Variable:	*Col. 2* Source:
Regional Housing Starts	Canadian Mortgage and Housing Corporation: Housing Starts, Completions and Under Construction Activity Ledgers
Regional Unemployment Rate	Statistics Canada - CANSIM II Database
Regional Employment Growth	Statistics Canada - CANSIM II Database
Regional Consumer Prices	Statistics Canada - CANSIM II Database
Ontario Real GDP	Ontario Ministry of Finance - Quarterly Ontario Economic Accounts
Ontario Real Manufacturing Output	Statistics Canada - CANSIM II Database
Ontario Wage Rate	Statistics Canada - CANSIM II Database
Ontario Retail Sales	Statistics Canada - CANSIM II Database
Ontario Housing Starts	Statistics Canada - CANSIM II Database
Ontario Consumer Prices	Statistics Canada - CANSIM II Database
Ontario Unemployment Rate	Statistics Canada - CANSIM II Database
Ontario Employment Growth	Statistics Canada - CANSIM II Database
1 Year Mortgage Rate	Statistics Canada - CANSIM II Database
3 Year Mortgage Rate	Statistics Canada - CANSIM II Database
5 Year Mortgage Rate	Statistics Canada - CANSIM II Database
Real Residential Natural Gas Price	Enbridge Gas Distribution Rate Handbook

Witnesses: I. McLeod
F. Ahmad

d) Please see below the year-to-date (Oct. 31) actual 2010 customer additions compared to last year's Board Approved budget.

Col. 1	*Col. 2*	*Col. 3*
Sector	2010 YTD Actual as of 31-Oct	2010 Board Approved Budget
Residential		
New Construction	22,451	22,616
Replacement	4,614	7,174
Total	27,065	29,790
Apartment		
New Construction	82	19
Replacement	3	7
Total	85	26
Commercial		
New Construction	1,182	1,665
Replacement	491	888
Total	1,673	2,553
Industrial		
New Construction	4	7
Replacement	-	3
Total	4	10
Total Customer Additions	28,827	32,379

e) A 1% change in the residential customer adds forecast for 2011 would result in an approximate change to the average number of ending customers by 177, (1,965,437 shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 17, would change by 177). The Row 18 distribution revenue required shown in that exhibit would change by approximately $75,000 or $0.1 million. The impact to rates from such a change, combined with a forecast volume change of 0.4 10^6 m^3, would be indiscernible.

Witnesses: I. McLeod
F. Ahmad

f) The 2010 housing starts forecasts in Column 7 of Table 1 at Exhibit B, Tab 1, Schedule 4, page 2, are the most recent projections.

g) The 2011 housing starts forecasts in Column 8 of Table 1 at Exhibit B, Tab 1, Schedule 4, page 2, are the most recent projections.

Witnesses: I. McLeod
F. Ahmad

VECC INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B Tab 1 Schedule 5 Page 13 Table 3

a) Provide a copy of Table 3 from last year's evidence

b) Compare and discuss the changes between the 2010 actual YTD data to the forecast

c) Discuss how the forecast changes in gas consumption play into the average use forecast

RESPONSE

a) Table 1 on the next page quantifies the volumetric impact of the average use driver variables on the residential sector provided from last year's evidence.

b) Consistent with previous filings, 2010 actual volumes will be filed as part of 2010 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. In accordance with the EB-2007-0615 Settlement Agreement, the Company will submit the 2010 actual results following the completion of Company's audited year end results approved for public release.

c) General service demand forecast methodology is discussed in the evidence found at Exhibit B, Tab 1, Schedule 5, beginning on page 2.

Table 1

Factors Influencing the Changes in Residential Gas Consumption

Between 2010 Test Year Budget and 2009 Bridge Year Estimate

Factors	**Total** Volume ($10^6 m^3$)	
Customer Growth	79.6	
DSM Initiatives	(13.7)	
New Homes - historical trend (a)	(9.2)	
Gas Prices	(3.0)	
Other Conservation (b)	0.0	*
Gas Appliances (c)	0.0	*
Growth Initiatives or Added Load (d)	0.5	
Total	54.2	

(a) Measured by vintage variable, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses based upon both historical building code, the new 2006 Building Code for new homes effective December 31, 2006, further changes to this 2006 Building Code effective December 31, 2008, and requiring near-full-height basement insulation effective December 31, 2009.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces and more energy efficient gas-fired storage water heaters for existing homes, and conservation initiatives originated by customers themselves or promoted by government programs, such as programmable thermostats, low-flow showerheads, and home renovations, other historical impact not reflected in the mentioned driver variables, etc.

(c) Measured by employment variable to reflect the demand for gas appliances or gas technologies.

(d) Added Load is based on the Company's added load initiatives, such as fuel switching, etc.

* Less than 50,000 m^3

Witness: R. Lei

VECC INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B Tab 1Schedule 5 Page 11 Para 19-22

a) Update the 2010 total volumes to reflect actual YTD

b) Discuss the main variances and implications for the 2011 forecast

RESPONSE

a) Consistent with previous filings, 2010 actual volumes will be filed as part of 2010 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. In accordance with the EB-2007-0615 Settlement Agreement, the Company will submit the 2010 actual results following the completion of Company's audited year end results approved for public release.

b) The 2010 Estimate volume of 11 151.6 10^6m^3 has been compared to the Board Approved 2010 Budget volume of 11 092.1 10^6m^3 in the evidence found at Exhibit B, Tab 1, Schedule 5, beginning on page 19. The 2010 Estimate is compared to the 2011 Budget volume of 11 306.3 10^6M^3 on page 11 of the same exhibit.

Witness: R. Lei

VECC INTERROGATORY #6

INTERROGATORY

Exhibit E, Tab 1, Schedule 1- Settlement Agreement

a) Provide the estimated YTD 2010 Average Use True Up Calculation in accordance with the EB-2007-0615 Settlement Agreement Paragraph 4.1 and the methodology regarding "Average Use True-Up Variance Account" or "AUTUVA")
b) Discuss whether (given the timing) this adjustment should be included in the 2011 DRR calculation or retained in the AUTUVA for disposition in spring 2011

RESPONSE

a) The purpose of the Average Use True-up Variance Account is to record (“true-up”) the revenue impact, exclusive of gas costs, of the difference between the annual forecast of average use for Rate 1 and Rate 6 and the actual normalized average use experienced during the year. In accordance with the IR Settlement as previously calculated, no mid year actual amount is posted to this account. The final amount will be posted to this account once the actual annual average use is calculated after year end (sometime in mid to late January 2011).

   Table 1 on the following page illustrates the estimated 2010 Average Use True Up Calculation in accordance with the settlement agreement calculation and methodology on the presumption that the actual 2010 actual data would be exactly same as the Bridge Year Estimate.

b) As noted above the purpose for the Average Use True-up Variance Account is to receive the actual amount once it is known in mid to late January 2011. This actual amount will then either be collected from, or rebated to, customers in a similar manner to other variance accounts in conjunction with the July 2011 QRAM as stated in evidence at Exhibit C, Tab 1, Schedule 1, page 4. Consequently, this adjustment should not be included in the 2011 DRR which would be consistent with previous regulatory filings and the Board approved settlement agreement.

Witnesses: I. Chan
K. Culbert

TABLE 1

2010 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT NUMERICAL ILLUSTRATION - 2010 BRIDGE YEAR ESTIMATE INFORMATION

Exhibit Reference:	EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 21	EB-2010-0146, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 23		EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 1		EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Tables 3-6				Unit Rate of the Revenue Impact, exclusive of gas costs	Collect dollars from rate payers, Debit AUTUVA, Credit Operating Revenues
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			=Col. 2-1		=Col. 3*4			=Col. 7-6	=Col. 5-8		=Col. 9*10
Rate Class	2010 Budget Annual Use (m^3)	2010 Bridge Year Estimate	Usage Variance (m^3)	Budget Customer Meters	Volumetric Variance (10^6m^3)	2010 DSM Budget (10^6m^3)	2010 DSM Actual (10^6m^3)	DSM Volumetric Variance (10^6m^3)	Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate ($/$m^3$)	AUTUVA: Revenue Impact, Exclusive of Gas Costs ($ millions)
1	2,622	2,619	(3)	1,772,699	(5.3)	(13.7)	(13.7)	0.0	(5.3)	0.0606	(0.32)
6	27,949	27,816	(133)	158,257	(21.0)	(26.6)	(26.6)	0.0	(21.0)	0.0368	(0.77)
Total					(26.4)	(40.3)	(40.3)	0.0	(26.4)		(1.10)

Witnesses: I. Chan
K. Culbert

VECC INTERROGATORY #7

INTERROGATORY

Ref: Exhibit B Tab 2 Schedule 2

a) Provide details of the treatment of the 2011 budget implications resulting from Emergency Assistance Under LEAP

b) Provide details/update of the Budgets for enhanced Low Income Prorams in 2011

c) Detail the regulatory treatment of these Low Income initiatives and what the impacts will be on the rates in 2011 and (forecast) 2012

d) Is EGD spending money on program development for the Multi-residential (non social housing)sector. If so provide details f the budgets initiatives and timing.

e) What is the upset $ limit on the use of the DSMVA for Low income spending relative to the base budget.?

f) What are the constraints on the use of DSMVA to enhance the LI programs (e.g. TRC)

RESPONSE

a) Under the Class Action Settlement in 2007, we are required to commit to the Winter Warmth program for 5 years with a financial commitment for $300,000 annually. Additionally, as part of the settlement, Enbridge paid $9 million to be invested with the United Way Toronto. These funds are invested annually with an average annual yield of approximately $350,000. These funds are incremental to our $300K. These two amounts total $650,000 to be paid out to the Winter Warmth program less administration fee of 15% to social agencies and 5% to United Way as the trustee of the Winter Warmth program. Under the LEAP program mandated by the Ontario Energy Board (the "Board"), we are required to top up these funds to reflect .12% of distribution revenues (approximately $1.2 million). This has a budget implication of

Witnesses: K. Culbert
A. Mandyam
M. Sousa
P. Squires

$500,000 to $600,000 incremental to the $650,000 designated for the Winter Warmth program.

b) Enbridge's Amended Low Income 2011 DSM Plan was filed with the Board on November 11, 2011 (EB-2010-0175, Exhibit B, Tab 2, Schedule 10). Details of the proposed budget are included in that Plan.

c) Enbridge's Amended Low Income 2011 DSM Plan was filed with the Board on November 11, 2011 (EB-2010-0175, Exhibit B, Tab 2, Schedule 10). This plan outlines Enbridge's proposal to use the 2011 DSMVA to record the incremental spending proposed in the plan (budgeted at $1,366,675). Accordingly, there will be no rate impact as a result of this expanded low income plan in 2011. There will be a one-time clearing of this variance account in 2012.

d) Enbridge has not budgeted specifically for program development in the Multi-residential (non social housing) sector.

e) In the EB-2006-0021 Decision With Reasons (the decision which currently governs Enbridge's DSM activities), there are no DSMVA rules or parameters specific to Low Income spending. For DSM programs in general, the EB-2006-0021 Decision states:

> Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility's DSM budget for that year. (EB-2006-0021 Decision with Reasons, page. 30)

Enbridge's proposal for use of the DSMVA for its Amended 2011 Low Income DSM Plan is outlined in EB-2010-0175, Exhibit B, Tab 2, Schedule 10, paragraph 12 and 13. These uses of the DSMVA for low income spending are incremental to, and independent of, the traditional use of the DSMVA outlined in EB-2006-0021. In other words, Enbridge would not have to reach its TRC savings target in the TRC-based portfolio in order to access the DSMVA for low-income spending; only the criteria outlined in EB-2010-0175, Exhibit B, Tab 2, Schedule 10, paragraph 13 would apply.

f) In the EB-2006-0021 Decision With Reasons (the decision which currently governs Enbridge's DSM activities), there are no DSMVA rules or parameters specific to Low Income programs. For DSM programs in general, the EB-2006-0021 Decision states that:

> The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis. (EB-2006-0021 Decision with Reasons, page. 13)

Enbridge's proposal for use of the DSMVA for its Amended 2011 Low Income DSM Plan is outlined in EB-2010-0175, Exhibit B, Tab 2, Schedule 10, paragraphs 12 and 13. These uses of the DSMVA for low income spending are incremental to, and independent of, the traditional use of the DSMVA outlined in EB-2006-0021. In other words, Enbridge would not have to reach its TRC savings target in the TRC-based portfolio in order to access the DSMVA for low-income spending; only the criteria outlined in EB-2010-0175, Exhibit B, Tab 2, Schedule 10, paragraph 13 would apply.

Witnesses: K. Culbert
A. Mandyam
M. Sousa
P. Squires

VECC INTERROGATORY #8

NO INTERROGATORY WAS ASKED BY VECC

VECC INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C Tab 1 Schedule 1 Page 8

Preamble: Enbridge has been advised by the actuary for its registered pension plan that there is a possibility of a material pension funding requirement, estimated to be in a range between nil and $20 million, in respect of Enbridge's pension plan in the 2011 fiscal year. At this time, Enbridge cannot be certain that the changes to pension plan regulations will result in a funding requirement in 201.

a) Provide a copy of the advice from the actuary

b) When will the next Pension Valuation be available?

RESPONSE

a) Please find the report from our actuary (Mercer) attached.

b) The 2011 pension contribution will be determined based on the Cost Certificate, which will be available in March 2011 and will provide the final status of the contribution requirement.

Witnesses: K. Culbert
T. Knight

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Chris Heller, FSA, FCIA
Principal

222 - 3rd Avenue SW
Suite 1200
Calgary, Alberta T2P 0B4
403 476 3253
Fax +1 403 261 6938
chris.heller@mercer.com
www.mercer.ca

Private & Confidential
Narin Kishinchandani
Director, Finance and Control
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, ON M2J 1P8

23 September 2010

Subject: Estimate of EGD RPP 2011 Funding Costs

Dear Narin:

As requested, we have estimated the expected 2011 minimum funding requirements for the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates ("EGD RPP").

Background

Regulatory Changes

Regulation 239/09 to the *Pension Benefits Act* of Ontario was filed on June 19, 2009 and included a number of changes to the Regulations. In particular, the following provisions were added or amended which resulted in the potential for contributions to be required for plan sponsors otherwise taking a contribution holiday:

- Section 7(3.1) – For fiscal years between July 1, 2009 and December 31, 2012, plan sponsors taking contribution holidays are required to file a Cost Certificate within 90 days of the start of the fiscal year as evidence that sufficient surplus[1] remains to justify the contribution holiday.

- Section 19(5) – If the plan sponsor knows or ought to know that the transfer ratio (ratio of hypothetical wind-up assets to liabilities) has decreased by 10% since the most recent filed valuation, the payment of commuted value lump sums must cease until approval is obtained from the Superintendent. Such approval would generally require the filing of a Cost Certificate and contributions to resume.

[1] On both a going-concern and solvency basis.

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In addition to the above, the Ontario government announced proposed pension reforms on August 24, 2010 which would result in contribution holidays being prohibited unless the transfer ratio is above 105% (the EGD RPP transfer ratio was 90% at December 31, 2009).

Financial Markets

The financial environment has not been favourable to pension plans in Canada in 2010. In particular, the health of pension plans has deteriorated due to the following events:

- Long term Government of Canada bonds yields have dropped by more than 70 bp as at August 31, 2010. Prescribed solvency interest rates are based on these yields, and a reduction in interest rates leads to an increase in liabilities.

- Equity markets have been relatively flat through August 31, 2010. Accordingly, most Canadian pension plans have received less than expected fund returns.

For a typical pension plan, these factors have resulted in a decrease in solvency and transfer ratios of approximately 7% as at August 31, 2010.

Implications for EGD

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Minimum contributions are determined by Ontario pension legislation, which include the changes noted above.

An actuarial valuation of the plan as at December 31, 2009 was filed with the Ontario pension regulator which specified minimum contribution requirements for both the DB and DC provision of the plan in 2010 to be nil. Accordingly, EGD's contribution holiday has been maintained through 2010.

If not for the regulation changes noted above, the contribution holiday could have been maintained through 2012 until the next valuation falls due regardless of interim plan experience. Even with the regulation changes, the contribution holiday was expected to continue for 3 – 5 years following the December 31, 2009 valuation if plan experience was as expected. However, poor experience as noted above has caused the financial health of the plan to deteriorate more than expected. Accordingly, contributions may be required starting in 2011.

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For EGD to maintain the contribution holiday in 2011, a Cost Certificate with continued evidence of plan surplus must be filed with the pension regulator in early 2011. The purpose of this letter is to show a range of possible outcomes of that Cost Certificate.

We have used the following three projection scenarios to estimate the December 31, 2010 financial position:

- Best estimate of asset returns for the remainder of 2010 and discount rates as at December 31, 2010 based on economic conditions as at August 31, 2010;
- Downside scenario with poor asset returns and decreased discount rates; and
- Upside scenario with better than expected asset returns and increased discount rates.

Estimated Financial Position at December 31, 2010

We have projected the results of the December 31, 2009 actuarial valuation of the EGD RPP to December 31, 2010 for the purpose of estimating the plan's financial position and determining whether or not the contribution holiday can be maintained in 2011. The assumptions and methods used in this projection are summarized below. For simplicity, we have only included the assets and liabilities with respect to the DB provision of the EGD RPP in the balance sheets shown below.

Going-concern Versus Solvency/Wind-up

The going-concern measure of the EGD RPP assumes that the plan continues indefinitely (i.e., pensions continue to accrue and the plan sponsor continues to exist). Pension legislation requires this type of valuation to assess the financial health of the pension plan on an ongoing basis to determine the contributions necessary to fund annual service accruals. Assumptions are needed for future unknown events such as salary increases, inflation, retirement patterns, and mortality. These assumptions are long-term in nature and are based on the actuary's best estimate with a margin for adverse deviations. Pension legislation requires that going-concern shortfalls be amortized over a maximum of 15 years.

The solvency/wind-up measure of the EGD RPP provides a snapshot of the plan assuming it is wound up on the valuation date, with no future pension accruals. Pension legislation

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requires this type of valuation to ensure the plan has sufficient assets to cover the prescribed benefits accrued to date. The wind-up valuation includes the value of all accrued benefits while the solvency valuation excludes the value of future cost-of-living adjustments (COLA). These assumptions are based on current market conditions and are prescribed by legislation. Pension legislation requires that solvency deficiencies be amortized over a maximum of 5 years. No contributions towards wind-up deficiencies are required, but they may be funded at the plan sponsor's discretion.

In addition, although minimum funding requirements do include a requirement to fund the going-concern current service cost, there is no requirement to fund the expected growth in the wind-up or solvency liabilities after the valuation date, which may be substantially larger than the going-concern current service cost. Therefore, funding the going-concern current service cost will generally result in a deterioration of the solvency financial position leading to special amortization payments being required in subsequent valuations.

Going-concern Balance Sheet at December 31, 2010

The table below details the actual going-concern financial position of the EGD RPP as at December 31, 2009, as well as the extrapolated position as at December 31, 2010.

Going-concern Financial Position ($ millions)

		12.31.2010 (Extrapolated)		
	12.31.2009 (Actual)	**Downside**	[redacted]	**Upside**
Assets	$698.7	$689.4	[redacted]	$720.7
Liabilities	$641.5	$686.9	[redacted]	$643.5
Funding excess (shortfall)	$57.2	$2.5	[redacted]	$77.2
Funded ratio	109%	100%	[redacted]	112%

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Solvency Balance Sheet at December 31, 2010

The table below details the actual solvency financial position of the EGD RPP as at December 31, 2009, as well as the extrapolated position as at December 31, 2010.

Solvency Financial Position ($ millions)

		12.31.2010 (Extrapolated)		
	12.31.2009 (Actual)	**Downside**	[redacted]	**Upside**
Assets	$698.1	$688.8	[redacted]	$720.1
Liabilities	$666.1	$746.2	[redacted]	$713.9
Solvency excess (deficiency)	$32.0	($57.4)	[redacted]	$6.2
Solvency ratio	105%	92%	[redacted]	101%

Wind-up Balance Sheet at December 31, 2009 (*FOR INFORMATION PURPOSES ONLY*)

The table below details the actual wind-up financial position of the EGD RPP as at December 31, 2009, as well as the extrapolated position as at December 31, 2010. Wind-up liabilities differ from solvency liabilities in that they include the value of all accrued benefits (specifically cost-of-living adjustments) which are excluded from the solvency measure. The wind-up deficiency is provided here for information purposes only, since it does not impact minimum contribution requirements.

Wind-up Financial Position ($ millions)

		12.31.2010 (Extrapolated)		
	12.31.2009 (Actual)	**Downside**	[redacted]	**Upside**
Assets	$696.7	$687.4	[redacted]	$718.7
Liabilities	$773.1	$858.0	[redacted]	$818.1
Wind-up excess (deficiency)	($76.4)	($170.6)	[redacted]	($99.4)
Wind-up ratio	90%	80%	[redacted]	88%

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Estimated 2011 Funding Costs

In general, minimum required contributions to a registered pension plan are determined based on actuarial valuations which must be filed with pension regulators at least once every 3 years (sometimes more frequently). Where a filed valuation shows a surplus[2], contribution holidays are permitted in the following year[3].

For subsequent years, where no report is being filed, the Ontario pension regulator requires evidence that the plan's financial position is still in surplus to justify the continued contribution holiday. This is the situation EGD currently faces. Therefore, a Cost Certificate showing continued surplus[2] must be filed in early 2011 to maintain the plan's contribution holiday over 2011. If this does not occur, contributions in respect of current service accruals (both DB and DC) must resume in 2011.
In addition to potential current service contributions, EGD is also required to pay a premium to the Ontario Pension Benefits Guarantee Fund ("PBGF") based on the financial position of the plan at the last filed valuation.

Note that if the December 31, 2010 valuation is not filed, there will be no requirement to amortize newly revealed going-concern or solvency deficiencies, if any, starting in 2011.

Summary of Minimum Required Contributions

The table below details estimated 2011 contribution requirements and PBGF premium for the EGD RPP. If the plan has either a going-concern or solvency deficit, minimum contributions are based on the current service cost shown in the December 31, 2009 valuation. Otherwise, the contribution holiday may continue. Note that total contributions to the EGD RPP were nil in 2010.

[2] On both a going-concern and solvency basis.
[3] The contribution holiday may apply to both DB and DC provisions.

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Estimated Minimum Required Contributions in 2011 ($ millions)

	Downside	[redacted]	Upside
DB current service cost	$15.2	[redacted]	$0.0
Special payments		[redacted]	
▪ going-concern	n/a	[redacted]	n/a
▪ solvency	n/a	[redacted]	n/a
Total DB contributions	$15.2	[redacted]	$0.0
DC current service cost	$1.5	[redacted]	$0.0
Total DB and DC contributions	**$16.7**	[redacted]	**$0.0**
		[redacted]	
PBGF Premium[4]	**$0.0**	[redacted]	**$0.0**

Data, Assumptions and Methods

The actual EGD RPP valuation results as at December 31, 2009 and the projected results as at December 31, 2010 are based on the following key assumptions:

Projection of Liabilities

		12.31.2010		
	12.31.2009	[redacted]	**Downside**	**Upside**
Going-concern discount rate	6.00%	[redacted]	-25 bp	+25 bp
Solvency discount rate		[redacted]		
▪ lump sum transfers	▪ 3.90%/10 yrs/5.40%	[redacted]	-20 bp	+20 bp
▪ annuities	▪ 4.49%	[redacted]		

[4] This amount is estimated to be $3,500 in 2011 (under all scenarios) based on the results of the December 31, 2009 valuation filed with the regulators.

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		12.31.2010		
	12.31.2009	[redacted]	**Downside**	**Upside**
Wind-up net discount rate ▪ lump sum transfers ▪ annuities	 ▪ 3.00%/10 yrs/4.10% ▪ 2.99%	[redacted]	-20 bp	+20 bp
All other assumptions	As described in September 2010 valuation report	[redacted]	Same	Same

Projection of Assets

		12.31.2010		
	12.31.2009	[redacted]	**Downside**	**Upside**
2010 asset returns	N/A	[redacted]	Same except 0.0% return after September 1, 2010	Same except 13.4% annualized (1.1% per month) return after September 1, 2010
Cash flows	N/A	[redacted]	Same	Same

Details on the data, assumptions, and methods utilized in the December 31, 2009 actuarial valuation of the EGD RPP can be found in our Report on the Actuarial Valuation for Funding Purposes as at December 31, 2009 (available shortly).

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Our projections assume that there are no significant changes in plan membership or demographics during 2010, and that all experience, other than that noted above, emerges as expected.

Solvency/Wind-up Assumptions

The basis upon which solvency/wind-up liabilities are valued is prescribed by the Canadian Institute of Actuaries ("CIA"). Actuaries rely on educational notes published by the CIA when setting assumptions, in particular, assumptions regarding the cost of purchasing annuities.

For members assumed to elect a deferred or immediate annuity in the December 31, 2009 valuation, solvency/wind-up liabilities were calculated using a discount rate which was 40 basis points above the yield on Government of Canada long term bonds. Based on the most recent guidance provided by the CIA[5], annuity purchase discount rates should incorporate a spread of 70 basis points above long-term government bond yields. Uncertainty in the market for pricing annuities may cause this spread to change at December 31, 2010. Therefore, the appropriate annuity purchase spread for valuations as at December 31, 2010 is unclear at this time.

[5] *Guidance for Assumptions for Hypothetical Wind-Up and Solvency Valuations Update – August 2010* (released August 30, 2010)

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Narin, please give us a call if you would like to discuss these results.

Sincerely,

Chris Heller, FSA, FCIA
Principal

Copy:
Ron Sawatzky, Enbridge Inc.
Tara Knight, Enbridge Gas Distribution Inc.
Allen Hornung, Mercer
Todd Wilson, Mercer

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VECC INTERROGATORY #10

INTERROGATORY

Ref: Exhibit E Tab 1, Schedule 1 Page 55- Settlement Agreement

a) Provide a schedule that compares the 2011 allocation to Rate Classes to that shown at page 55 of the EB-2007-0615 Settlement Agreement.

b) Comment on the differences for the Rate 1 and Rate 6 classes

RESPONSE

a) Although the interrogatory specifies that the 2011 allocation to rate classes be compared to page 55 of the EB-2007-0615 Settlement Agreement, page 55 refers to the 2010 test year. We assume that VECC intends to compare the 2011 allocation to the 2011 test year as shown at page 56 of the Settlement Agreement. This response reflects that interpretation.

   A similar schedule to Exhibit E, Tab 1, Schedule 1, page 56, was provided as part of the 2011 Application (EB-2010-0146) at Exhibit B, Tab 3, Schedule 10, page 7. Both exhibits are provided on the next page for ease of comparison.

b) The assignments of DRR before Y factors for 2011 (Table 2, item 1.0) have remained consistent with the estimates for 2011 from EB-2007-0615 as contained in the Settlement Agreement and reproduced in Table 1, item 1.5.

   The assignments of Total DRR with Y factors for 2011 (Table 2, item 1.6) have also remained consistent with the estimates for 2011 from the Settlement Agreement (Table 1, item 1.0) as the relative amounts and assignments of the Y factors are comparable.

   Rate 1 assignment for 2011 is slightly lower than the estimate. Rate 6 assignment is higher than the estimate, reflecting customer migration from contract rates to Rate 6. Please note that the Company's IRM Model allows forecasts and allocators to be updated annually. This ensures that the assignment of revenue requirement by rate class and consequently rate impacts, remains responsive to factors such as customer growth, volumetric gains or losses, and customer migration between various rates and service offerings.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

Table 1: Settlement Agreement (page 56)

2011																
Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	Total DRR	1,006.4	673.5	262.2	1.3	27.6	11.2	8.4	6.4	0.7	4.9	5.3	2.3	0.4	0.2	1.6
	Y Factor: Other															
1.1	2011 Gas in Storage & Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2011	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2011	89.2	82.0	7.1	-	-	-	-	-	-	-	-	0.0	-	-	
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.0	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	-	-	0.0	-	-	
	Total Y-Factor	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	0.0
1.5	Total DRR minus Y-Factor	846.8	558.1	230.4	1.3	22.6	9.8	6.8	6.3	0.6	3.8	2.8	1.7	0.4	0.2	1.6

Table 2: 2011 Application – EB-2010-0146, Exhibit B, Tab 3, Schedule 10, page 7

2011 Distribution Revenue Requirement with Y- Factor Detail
December 31, 2011
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	DRR before Y- Factors	828.7	552.8	244.3	0.2	0.0	7.9	3.9	7.1	0.7	4.0	2.4	2.1	0.3	0.1	2.9
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	30.9	15.3	13.6	0.0	0.0	0.3	0.1	0.0	0.0	0.5	0.7	0.4	0.0	0.0	0.0
1.2	DSM 2011	26.7	10.3	9.9	0.0	0.0	1.7	1.5	0.0	0.0	1.6	1.8	0.0	0.0	0.0	0.0
1.3	CIS/ Customer Care 2011	97.4	89.4	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Total Y-Factor	158.5	116.6	32.9	0.0	0.0	2.1	1.6	0.2	0.0	2.2	2.5	0.5	0.0	0.0	0.0
1.6	DRR with Y-Factors	987.2	669.4	277.2	0.2	0.0	9.9	5.5	7.3	0.7	6.2	4.9	2.6	0.3	0.1	2.9

Witnesses: J. Collier
A. Kacicnik
M. Suarez

VECC INTERROGATORY #11

INTERROGATORY

Exhibit E Tab 1, Schedule 1 Page 58- Settlement Agreement

a) Provide an update and comparison to the Schedule shown at Page 58, including actual and forecast rate impacts and actual and forecast base DRRs 2008-2012.

b) Provide an update/comparison of Bill impacts2008-2012 in the schedule on Page 59 of the settlement Agreement.

RESPONSE

a) Please see Table 1 on page 2.

b) Please see Table 2 on page 3.

Witnesses: J. Collier
A. Kacicnik

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008[1] T-Service Rate Impact Estimate	ADR 2008[1] T-Service Rate Impact Approved[6]	ADR 2009[2] T-Service Rate Impact Estimate	ADR 2009[2] T-Service Rate Impact Approved[7]	ADR 2010[3] T-Service Rate Impact Estimate	ADR 2010[3] T-Service Rate Impact Approved[8]	ADR 2011[4] T-Service Rate Impact Estimate	ADR 2011[4] T-Service Rate Impact Proposed[9]	ADR 2012[5] T-Service Rate Impact Estimate
1	0.1%	0.3%	2.1%	0.5%	1.6%	0.2%	1.5%	-0.8%	1.7%
6	0.0%	0.1%	1.8%	0.4%	1.3%	0.0%	1.2%	-1.5%	1.4%
9	0.1%	0.1%	0.8%	0.0%	1.1%	0.2%	1.2%	-0.4%	1.6%
100	0.1%	0.1%	1.3%	-0.3%	1.0%	0.2%	0.9%	-2.2%	0.9%
110	0.1%	0.1%	1.1%	-0.3%	1.0%	0.2%	0.9%	-3.6%	0.9%
115	0.1%	0.1%	1.1%	-0.4%	0.8%	0.2%	0.8%	-4.3%	0.8%
135	0.6%	0.6%	0.9%	-0.1%	0.9%	0.2%	0.9%	-4.7%	0.9%
145	0.2%	0.2%	1.0%	0.0%	0.9%	0.2%	0.8%	-3.6%	0.8%
170	0.4%	0.4%	1.0%	-0.4%	0.9%	0.3%	0.9%	-5.5%	0.9%
200	0.4%	0.4%	1.0%	0.0%	0.9%	0.1%	0.8%	-3.2%	1.0%

	ADR 2008 Distribution Rate Impact		ADR 2009 Distribution Rate Impact		ADR 2010 Distribution Rate Impact		ADR 2011 Distribution Rate Impact		ADR 2012 Distribution Rate Impact
125	0.0%	0.0%	0.7%	0.1%	0.7%	0.3%	0.7%	0.4%	0.7%
300	0.1%	0.1%	0.9%	0.1%	0.9%	0.3%	0.9%	0.4%	0.9%

Notes:
1. - 2008 Distribution Revenue Requirement of $935 M (Estimate), 2008 Distribution Revenue Requirement of $938 M (Approved)
2. - 2009 Distribution Revenue Requirement of $963 M (Estimate), 2009 Distribution Revenue Requirement of $974 M (Approved)
3. - 2010 Distribution Revenue Requirement of $986 M (Estimate), 2010 Distribution Revenue Requirement of $981 M (Approved)
4. - 2011 Distribution Revenue Requirement of $1,006 M (Estimate) , 2011 Distribution Revenue Requirement of $989 M (Proposed)
5. - 2012 Distribution Revenue Requirement of $1,029 M
6. - From EB-2007-0615, Exhibit C, Tab 6, Schedule 8
7. - From EB-2008-0219, Exhibit B, Tab 3, Schedule 1, Page 4
8. - From EB-2009-0172, Exhibit B, Tab 4, Schedule 1, Page 3
9. - From EB-2010-0146, Exhibit B, Tab 3, Schedule 1, Page 3

Typical Customer Estimated T-Service Bill Impacts from 2008 to 2012
As Per Settlement Proposal

	October 1, 2007 T-Service Bill (1) Annual Bill ($)	Estimated 2008 T-Service Bill Annual Bill ($)	Approved 2008 T-Service Bill Annual Bill ($)	Estimated 2008 T-Service Bill Annual $ change	Approved 2008 T-Service Bill Annual $ change	Estimated 2009 T-Service Bill Annual $ change	Approved 2009 T-Service Bill Annual $ change	Estimated 2010 T-Service Bill Annual $ change	Approved 2010 T-Service Bill Annual $ change	Estimated 2011 T-Service Bill Annual $ change	Proposed 2011 T-Service Bill Annual $ change
Rate 1											
Rate 1 T-Service Bill Impact	409.37	416.18	416.66	6.81	7.29	8.68	8.07	6.93	6.73	6.45	(0.30)
Note: (1) based on annual consumption of 1,955 m3											
Rate 1 T-Service Bill Impact	558.77	559.89	556.36	1.12	(2.41)	11.67	(0.94)	9.32	(2.95)	8.67	(7.21)
Note: (1) based on annual consumption of 3,064 m3											
Rate 1 T-Service Bill Impact	772.67	755.35	756.56	(17.32)	(16.11)	15.75	(13.66)	12.57	(16.72)	11.70	(17.12)
Note: (1) based on annual consumption of 4,691 m3											
Rate 6											
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2,844.04	2.88	(35.86)	51.73	26.51	39.42	6.94	36.71	(40.76)
Note: (1) based on annual consumption of 22,606 m3											
Rate 6 T-Service Bill Impact	5,023.61	4,710.21	4,716.59	(313.40)	(307.02)	84.52	(5.71)	64.40	(37.88)	59.99	(127.02)
Note: (1) based on annual consumption of 43,285 m3											
Rate 115											
Rate 115 T-Service Bill Impact	3,356,187.92	3,359,795.82	3,358,151.13	3,607.90	1,963.21	36,957.75	(19,803.81)	25,690.51	6,906.39	25,723.00	(193,239.28)
Note: (1) based on annual consumption of 69,832,850 m3 at 80% Load Factor											

VECC INTERROGATORY #12

INTERROGATORY

Ref: Exhibit B Tab 3 Schedule 1 para 23-25 Plus Appendix

a) Provide the details of the costs underlying new System Gas Administration charges.(similar to Appendix A for DPAC, except include derivation of incremental costs)

b) Compare to historic costs

c) Delineate the change in the allocation of this cost to system gas customers

d) Provide the 2011 (forecast) of system gas customers in each class compared to 2010 (forecast and Actual)

e) Is the SG admin charge a fixed or variable cost (or both)

RESPONSE

a) and b)

Please see the response to Direct Energy's Interrogatory at Exhibit I, Tab 3, Schedule 1, page 1, part b.

c) As per the Ontario Energy Board's Decision in EB-2008-0106, there is no change in the allocation methodology of incremental costs to support System Gas Management to customers. Only the level of incremental costs is updated each year. The cost is allocated to rate classes on the basis of System Gas Sales (volumetric), thereby resulting in the same unit rate for each rate class (see Exhibit B, Tab 3, Schedule 7, page 1, Line 3.3). The 2011 proposed system gas fee equals 0.0235 cents/m^3 for all rate classes. The System Gas Fee is recovered as part of the Gas Supply Charge.

d) Please see Table 2 in the response to Just Energy's interrogatory at Exhibit I, Tab 5, Schedule 3, page 1. Please note that incremental system gas management costs are allocated to rate classes on the basis of system gas sales volumes, not system gas customers.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

e) As highlighted in response to part c) above, the System Gas Fee is a variable charge recovered as part of the Gas Supply Charge to System Gas customers. The same unit rate of 0.0235 cents/m^3 applies to all system gas customers in all rate classes in 2011.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

VECC INTERROGATORY #13

INTERROGATORY

Exhibit B, Tab 3, Schedule 2 Rate 1 – Rate Schedule

a) Provide details of the agreement in the EB-2007-0615 Settlement Agreement regarding Residential Customer Charges.

b) Provide details of the 2007 (base), 2008, 2009 and 2010 residential customer charges.

c) Explain why the Increase in the 2011 Customer charge from $18.00 to $19.00 is appropriate and in line with the Settlement Agreement.

d) For a low volume Residential customer with most consumption in the first rate block provide a schedule that shows the impact on the Distribution portion of the bill and total bill impact of the $1.00 change in customer charge. Compare this to the average DRR change and average total bill impact.

RESPONSE

a) and b)

The 2007 Monthly Residential Customer Charge was $11.95. The following table outlines the annual changes to Monthly Residential Customer Charges agreed upon in the Settlement Agreement:

Changes to Monthly Customer Charges ($)	
Year	Rate 1
2008	$14.00
2009	$16.00
2010	$18.00
2011	$19.00
2012	$20.00

This information can be found at Exhibit E, Tab 1, Schedule 1, page 33, of the Settlement Agreement.

Witnesses: J. Collier
A. Kacicnik

c) The 2011 customer charge increase from $18.00 to $19.00 reflects Section 12.3.1 of the Settlement Agreement, as shown in the table in response to a) and b). As is agreed upon in this section, the current Board-approved rate design principles have been maintained, and the agreed upon monthly charge increase has been made on a revenue neutral basis within the rate class.

d) A low volume customer consumes approximately 1,081 m^3 per year and generally uses natural gas for water heating and one other life style application such as a natural gas fireplace or natural gas range. This type of customer represents approximately 1% of the residential customers on Enbridge's system. The average residential customer uses natural gas for space and water heating and consumes approximately 2,643m^3 per year. Approximately 90% of Enbridge customers use natural gas for space and water heating.

Impacts for General & Water Heating and Average Customers are shown in the following table.

Residential Customer Type With Annual Consumption		T-Service % Impact	Total % Bill Impact
General & Water Htg. (1,081m^3)		1.4%	1.0%
Average Customer (2,643m^3)		-0.8%	-0.4%

Witnesses: J. Collier
A. Kacicnik

VECC INTERROGATORY #14

INTERROGATORY

Ref: Exhibit B Tab 5 Schedule 1 and Exhibit CTab 1Schedule 1

a) Provide details of the costs underlying the Manufactured Gas Plant D/A 2010 MGPDA and August 31 Balance of $248,500 plus interest of $11,500 and year end forecast of $ 373,500 plus interest of $12,600

b) Confirm that the balance in the 2010 Manufactured Gas Plant DA ("MGPDA") will be transferred into a 2011 MGPDA

c) With regard to Open Bill Service D/A 2010 OBSDA August 31 Balance of $464,.5 plus interest of$17.5 and year end balance of $438,.500 plus interest of $19,100 and. Open Bill Access V/A 2009 OBAVA 423.1 7 .3 397.2 8.8 confirm that the EB-2009-0043 Settlement Agreement indicates the balances in the 2008 Open Bill deferral and variance accounts would be transferred to 2011 accounts.

d) EGD indicates that the first year of clearance commenced in April, 2010 and in July 2011 the Company will clear approximately one half of the remaining balance in the 2010 OBSDA and 2010 OBAVA..Indicate details of how the balances will be presented and subject to prudence review and disposition

RESPONSE

a) The costs within the August 31 balance and forecast year-end balance are in relation to external legal costs incurred to date and potentially by year end in relation to the ongoing Manufactured Gas Plant ("MGP") legal suit.

b) As the MGP legal suit is still ongoing, the actual balance within the account at the end of 2010 will be rolled forward or transferred into a 2011 MGPDA.

c) The EB-2009-0043 Board Approved Open Bill Settlement Agreement and the EB-2009-0172 Board Approved Rate Order account description indicate that 50% of balances in these accounts will be recovered from ratepayers in three installments in 2010 through 2012 with the other 50% to be drawn down over the same period to the account of Enbridge. The amounts in the accounts at the end of each year represent the unrecovered and un-cleared remaining balances which will be rolled forward into the following year's account until clearance is complete.

Witnesses: K. Culbert
A. Kacicnik
D. Small

d) The evidence erroneously indicated that ratepayer amounts approved for recovery relating to the Open Bill accounts had commenced in April 2010 along with the clearance of other deferral and variance accounts. In fact, the first installment of recovery from ratepayers will occur with the clearance of deferral and variance accounts commencing in January 2011. The second of three installments to be recovered is anticipated to occur in July 2011. The balances to be cleared through these accounts were agreed to and approved by the Board within the EB-2010-0042 proceeding. The Company will file support for the amounts recovered / cleared and what the residual balances should be in a continuity schedule within the 2010 earnings sharing and deferral and variance account application and proceeding.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #15

INTERROGATORY

Ref: Exhibit B Tab 5 Schedule 1

a) Provide an updated copy of EGD's IFRS Compliance Plan

b) With regard to the. International Financial Reporting Standards Transition Costs D/A (2010 IFRSTCDA) balance of $1,733.4 plus interest provide more details of the Costs incurred relative to the milestones in the plan

c) Provide a forward projection 2011-2012 of IFRS Compliance costs relative to the Plan

RESPONSE

Enbridge is not seeking approval of clearance of the 2010 IFRSTCDA within this proceeding. As per the parameter of the EB-2007-0615 IR settlement agreement and as indicated in the response to VECC Interrogatory #1 found at Exhibit I, Tab 7, Schedule 1, the Company will file an ESM and Deferral and Variance account review application as soon as reasonably possible after the public release of 2010 year-end financial results. The opportunity to review elements relating to the IFRSTCDA should occur within that proceeding and is not required for the purpose of this proceeding, which is to establish the 2011 IR formula revenue requirement.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #16

INTERROGATORY

Ref: Exhibit B Tab 5 Schedule 1

a) With regard to 2009Transactional Services D/A (2009 TSDA) and balance ($7,062,100) and 2010 Transactional Services D/A (2010 TSDA) ($2,972.9))

b) Provide details of the significant change in 2010 revenues. Alternatively if there is a plan for prudence review and disposition of these amounts indicate when/how ratepayers will be provided with an opportunity to review the details

RESPONSE

The amount of Transactional Services revenue generated each year is a function of various market conditions specific to that year. These market conditions would include differences in North American demand for Natural Gas at various import / export points and price volatility between summer and winter periods.

The forecasted 2010 TSDA amount provided at Exhibit B, Tab 5, Schedule 1, will be updated with actual information when it is available and like other deferral account balances subject to review as part of the 2010 ESM proceeding.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #17

INTERROGATORY

Ref: Exhibit D Tab 1 Schedule 2 Table 1

a) Provide an explanation for the change in NDTRAC 2008 Actual 97.7% to 2009 94.3%

RESPONSE

a) The 2008 Reconnect Response Time has been revised to 97.1%, as part of the current OEB audit review of our Service Quality Indicators.

The drop from 97.1% in 2008 to 94.3% in 2009 occurred during the second half of 2009 and was impacted by the roll-out of SAP, requiring increased use of manual business processes to meet seasonal volumes and SQR levels.

The 2009 result of 94.3% is, however, well above the OEB SQR target of 85%.

Witnesses: T. Ferguson
K. Lakatos-Hayward

VECC INTERROGATORY #18

INTERROGATORY

Ref: Exhibit E Tab 3 Schedule 1 Pages 1 and 2

Preamble: The Company will indicate, within its 2011 earnings sharing application, which methodology it employs for the calculation of 2011 earnings sharing.

a) Explain in detail why EGD is presenting the second methodology A2 given the Board's EB-2010-0042 Decision that the Methodology A1 should be used during the IRM period?

RESPONSE

Enbridge has presented both methodologies because the Ontario Energy Board's EB-2010-0042 Decision regarding the A1 methodology is the subject of an appeal that is pending before the Ontario Divisional Court.

Witnesses: I. McLeod
S. Murray