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July 19, 2012

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")
Ontario Energy Board File No. EB-2013-0046
2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review
Enbridge Interrogatory Responses

In accordance with the Ontario Energy Board's (the "Board") Procedural Order issued for the above noted proceeding, enclosed please find the interrogatory responses of Enbridge.

Also attached please find Exhibit C, Tab 1, Schedule 6 with updates on pages 11 and 12 only.

Included in the package please find a CD which consists of all pre-filed evidence and the interrogatory responses.

This submission was filed through the Board's RESS and will be available on the Company's website at www.enbridgegas.com/ratecase .

Please contact the undersigned if you have any questions.

Yours truly,

[original signed by]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties in EB-2011-0354

I – Interrogatory Responses

1 – Board
Staff

BOARD STAFF INTERROGATORY #1

INTERROGATORY

ISSUE 1. Are the deferral and variance accounts and balances proposed for disposition on the attached schedule ("Schedule 1") appropriate?

Ref: ExA/T2/S1/Appendix A

(i) Please list the accounts and associated balances that have already undergone a formal Board review process including an order approving the amount for clearance.

(ii) Which accounts listed for clearance are expected to be reviewed separately in a future Board proceeding (other than the instant

RESPONSE

(i) Within the list of accounts being requested clearance of in Exhibit A, Tab 2, Schedule 1, Appendix A, the Board approved the TIACDA in the EB-2011-0354 Settlement Agreement, Issue D4, allowing the recovery of Other Post-Employment Benefit ("OPEB") expenses, of $90 million, evenly over a twenty year period commencing in 2013. The approved OPEB expenses are recorded in the 2013 Transition Impact of Accounting Changes Deferral Account ("TIACDA"). The $90 million approved in EB-2011-0354 was a forecast amount, which has since been updated to the final actual amount of $88.7 million. One twentieth of $88.7 million, or $4.4 million, is proposed for clearance in this proceeding.

(ii) The Company expects to file the EB-2013-0075 application by the end of July 2013, in which the Company will be seeking approval to clear the 2011 DSMVA, 2011 SSMVA, and 2011 LRAM balances. As indicated in Exhibit C, Tab 1, Schedule 1, page 2, footnote 1, the final 2011 DSMVA, SSMVA, & LRAM balances to be cleared will be those approved by the Board within the EB-2013-0075 proceeding. The Company anticipates that a Board Decision in the EB-2013-0075 proceeding will be received in sufficient time to allow clearance to occur in conjunction with accounts approved in this proceeding, which are being requested for clearance in January 2014.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

ISSUE 1. Are the deferral and variance accounts and balances proposed for disposition on the attached schedule (“Schedule 1”) appropriate?

Ref: ExB/T1/S1/

This exhibit lays out the earnings sharing calculation and methodology.

Have there been any methodology changes in the calculation of the ESM since the last ESM clearance proceeding (EB-2012-0055) in which the 2011 ESM was approved? If so, please describe what has changed.

RESPONSE

No changes in methodology were made to the way the 2012 earnings sharing amount was calculated, as compared to the 2011 ESM calculation. However, as a result of the Company’s adoption of U.S. Generally Accepted Accounting Principles (“GAAP”), for financial reporting purposes in 2012, additional adjustments were required to ensure utility results and the corresponding ESM calculation were derived in accordance with Canadian GAAP, which were the accounting principles in place when the IR plan was developed and approved in EB-2007-0615. The adjustments were made to comply with Issue 10.1, Part (ii), in the EB-2007-0615 Approved Settlement Agreement, which stipulates:

> *for the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;*

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

ISSUE 1. Are the deferral and variance accounts and balances proposed for disposition on the attached schedule (“Schedule 1”) appropriate?

Ref: ExB/T1/S4/page 3 of 4 / Reconciliation of 2012 Audited EGDI to Utility Income

Listed on this schedule is a $16.8 million elimination of Corporate Cost Allocations above RCAM amount.

Please list the actual CAM amount versus the RCAM amounts for 2008 through 2012 together with a variance column.

RESPONSE

	CAM	RCAM	Variance
2008	32.2	19.1	13.1
2009	34.2	21.1	13.1
2010	36.7	24.3	12.4
2011	43.4	26.7	16.7
2012	48.4	31.6*	16.8

*includes adjustment recommended by MNP report

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

BOARD STAFF INTERROGATORY #4

INTERROGATORY

ISSUE 1. Are the deferral and variance accounts and balances proposed for disposition on the attached schedule ("Schedule 1") appropriate?

Ref: ExB/T3/S4/page 4 of 5 / Adjustments to EGDI Corporate Revenue

Listed on this schedule are 2012 Open bill revenue adjustments.

Please list the actual Open bill revenue for 2008 through 2012, the shareholder amount, and the ratepayer guarantee amount.

RESPONSE

The following table summarizes Open Bill results for 2008 through 2012.

Open Bill Services

($000's)	2012	2011	2010	2009	2008
Open Bill revenues (including bill inserts)	19,894.3	19,264.2	19,095.4	17,267.3	16,844.9
Open Bill expenses (including EGD share of OBSDA & OBAVA clearance)	(13,214.3)	(12,545.0)	(11,899.1)	(10,718.6)	(10,653.5)
Net revenues	6,680.0	6,719.2	7,196.3	6,548.7	6,191.4
Add back EGD portion of OBSDA & OBAVA clearance	169.3	167.1	171.3	-	-
Adjusted net revenues	6,849.3	6,886.3	7,367.6	6,548.7	6,191.4
Ratepayer guarantee (included in rates)	5,389.0	5,389.0	5,389.0	5,389.0	5,389.0
EGD portion of net reveues	1,460.3	1,497.3	1,978.6	1,159.7	595.0
Ratepayer portion of Bill Insert revenues transferred to the OBSDA					207.4
Ex-franchise Open Bill revenues	790.0	1,285.3	1,168.6	320.8	-
Ex-franchise Open Bill expenses	(504.1)	(816.5)	(664.7)	(265.0)	-
Net Ex-franchise revenues	285.9	468.8	503.9	55.8	-
Ratepayer portion of net revenues transferred to the EFTPBSDA	143.0	234.4	252.0	27.9	-
EGD portion of net revenues eliminated from utility results	143.0	234.4	252.0	27.9	-

Witnesses: K. Culbert
M. Fenn
T. Ferguson
R. Small

BOARD STAFF INTERROGATORY #1

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/page 7 of 21 para 14

Preamble: In paragraph 14, the evidence states that "To be considered transactional services the opportunities must be unplanned, a third party must be requesting a service and EGD must have temporarily surplus capacity".

These three conditions appear to be an articulation of EGD's principles of what constitutes a valid transactional service. Please comment on whether this is a fair characterization. Is every potential TS opportunity screened on this basis before it is approved? Please explain.

RESPONSE

The three conditions described above and further qualified in subsequent paragraphs 15, 16 and 17 of the evidence must exist for a transaction to be treated as a Transactional Service transaction.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/page 14 of 21 para 28

Preamble:
In paragraph 28, the evidence states that:

“An alternative to a base exchange like the Iroquois/Dawn exchange example used earlier, would be for EGD to give gas to a third party at Empress (instead of Iroquois) and still receive the gas back from the third party at Dawn. The only added nuance would be that, instead of using its TCPL long haul contract to deliver the gas at Iroquois, EGD would temporarily assign the associated long haul capacity to the third party. From EGD’s perspective, nothing is different from the earlier base exchange example. EGD exchanged its gas and its transportation capacity for equivalent gas delivered at Dawn for injection into storage.”

How is EGD assured that this gas will be delivered by the third party at Dawn? What is the consequence if the third party defaults and the gas fails to appear? Please discuss the risks involved, the implications for the gas supply plan, and how EGD would recover from such a default.

RESPONSE

Before EGD enters into any Transactional Services arrangement counterparties are required to sign an agreement and are subject to a corporate risk assessment to determine their credit worthiness. Attached is a copy of the Transactional Services Agreement which includes provisions in the event of default of delivery by the counterparty as well as the requirement for a letter of credit. If in the event that a customer failed to deliver the volume specified in the Exchange Agreement and EGD purchased replacement gas then EGD would use the amounts received under paragraph 4.6 of the Transactional Services Agreement to offset any incremental cost incurred.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

Once counterparties have been approved as credit worthy counterparty the Gas Supply group is permitted to enter into Transactional Services arrangements. Included in the attached are copies of the "Transportation Exchange Service Transaction Confirmation" which would contain all the particulars of an Exchange agreement whether it be a Base Exchange, an STS-RAM Exchange or a Capacity Release Exchange; the "Storage Service Transaction Confirmation" and while the attached includes a "Loan Service Transaction Confirmation" EGD does not enter into Loan Arrangement because we have chosen not to tak e on the risk associated with loaning a counterparty gas.

TRANSACTIONAL SERVICES CONTRACT

BETWEEN

ENBRIDGE GAS DISTRIBUTION INC. ("EGDI")

AND

[Insert Name of Customer] ("CUSTOMER")

BASE CONTRACT FOR TRANSACTIONAL SERVICES

Enbridge Gas Distribution Inc.	Customer:
3000, 425 1st Street S.W., Calgary, AB, T2P 3L8	Address:
Duns Number: 25-146-1455	Duns Number:
GST Number: 105205140	GST Number:
Fed ID: 98-0500188	
Notices:	Notices:
Contract Administration	
Email: ContractsAdmin@Enbridge.com	Phone:
Fax: (403) 231-4848	Fax:
Confirmations:	Confirmations:
EnbridgeConfirmations@Enbridge.com	
Phone: (403) 231-3972	Phone:
Fax: (403) 231-5780	Fax:
Invoices and Payments:	Invoices and Payments:
Natural Gas Accounting	
Phone: (416) 758-4346	Phone:
Fax: (416) 495-5354	Fax:
Nominations:	Nominations:
Gas Control (Edmonton)	
Phone: (780) 420-8850	Phone:
Fax: (780) 420-8533	Fax:
E-mail: sms@enbridge.com	
Wire Transfer of ACH Numbers (if applicable):	Wire Transfer of ACH Numbers (if applicable):
See Exhibit "B"	

.

This Transactional Services Contract is entered into as of [DATE], between Enbridge Gas Distribution Inc. ("EGDI") and ("Customer").

ARTICLE I
DEFINITIONS

- "Affected Transaction" means a Firm Transaction with a Delivery Period of at least 30 Days in respect of which there has occurred that number of Failure Days that is equal to the greater of (i) 4 Days; or (ii) 5% of the number of Days in the Delivery Period.

- "Affiliate" of any person, including without limitation, a partnership, means a person, including without limitation, a partnership, which directly or indirectly, controls, is controlled by, or is under common control with such person. For the purpose of this definition "control" means control in fact, whether by ownership of sufficient voting securities to elect a majority of the directors of a corporation, by owning sufficient partnership interest in an ordinary partnership, by being the general partner of a limited partnership, by contract or otherwise, but shall exclude in the case of Customer, any such person that is not organized or existing under the jurisdiction of Canada or the United States or a political subdivision thereof and "person" includes any individual, a partnership (including, without limitation, a limited partnership and a limited liability partnership), a corporation (including, without limitation a limited liability corporation), an unlimited company, a joint stock company, a trust, a joint venture, an unincorporated organization, a union, a government or any department or agency of a government, and the heirs, executors, administrators, or other legal representatives of an individual.

- "Base Contract" means the body of this agreement that sets forth the terms and conditions for the provision of Transportation Exchange Services, Storage Services, Loan Services, and Capacity Release Services.

- "Business Day" means any day except Saturday, Sunday, or a statutory or banking holiday observed in the jurisdiction specified pursuant to Article 16.5. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the receiving party's address for Notices as provided pursuant to Article 13.1.

- "Buyer" when used in the definition of "Termination Payment" refers to the party receiving or accepting Gas pursuant to a Transaction.

- "Capacity Release Services" means a Transactional Service whereby EGDI assigns a portion of its contracted third party transportation capacity, and all of the rights and obligations thereunder, to Customer for a defined period of time.

- "Claiming Party" means the party claiming a suspension of its obligations due to Force Majeure.

- “Confirm Deadline” means 5:00 p.m. in the receiving party’s time zone on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

- “Contract” means the legally binding relationship established by (i) the Base Contract, (ii) any and all effective Transaction Confirmations and (iii) any and all Transactions entered into by the parties either orally or electronically.

- “Contract Quantity” means the quantity of Gas to be delivered, received or redelivered each Day pursuant to a Transportation Exchange Service Transaction.

- "Contract Value" of a Transaction means the net present value (applying the Present Value Discount Rate) of the product of (i) the quantity of Gas remaining under a Transaction which the parties are obligated to transact multiplied by (ii) the applicable Transactional Service Fee.

- “Costs” means all reasonable costs, legal fees and expenses incurred by the Non-Defaulting Party to replace a Transaction(s), or in connection with termination of a Transaction(s) pursuant to Article XIV, including, without limitation, legal fees as between a solicitor and its client, brokerage fees, commissions and expenses incurred in maintaining, replacing or liquidating any terminated Transactions.

- “Credit Rating” means, with respect to a party or entity on any date of determination, the rating then assigned to its unsecured and senior unsubordinated long-term debt obligations (not supported by third party credit enhancement) by a Designated Rating Agency or, if the obligations of that party under the Contract are guaranteed by a Credit Support Provider, the rating then assigned to the Credit Support Provider’s unsecured and senior unsubordinated long-term debt obligations (not supported by third party credit enhancement) by a Designated Rating Agency. The applicable rating of the party or its Credit Support Provider, as the case may be, will be the lowest Credit Rating as of that date.

- “Credit Support Provider” means a third party, acceptable to both parties, that has guaranteed, or otherwise provided credit support for, the obligations of a party under the Contract on terms acceptable to the other party hereto.

- “Customer Nominated Volume” means the volume of Gas required to be nominated by the Customer on a Day during the term of a Transportation Exchange Services Transaction, such volume being prescribed by the terms of the applicable Transportation Exchange Services Transaction Confirmation.

- “Customer Unaccepted Volume” means the volume of Gas equal to the amount obtained by subtracting the amount of Gas accepted by the Customer at the Delivery Point from the Daily Redelivered Volume.

- “Daily Delivered Volume” shall have the meaning given to it in Article 4.2.

- “Day” means 9:00 a.m. to 9:00 a.m. central time.

- “Dekatherm” means one million British Thermal Units.

- “Defaulting Party” shall have the meaning given to it in Article 14.4.

- “Delivery Period” means the period during which deliveries are to be made as set forth in the Transaction Confirmation.

- "Delivery Point(s)" means such point(s) of delivery of Gas pursuant to a Transaction.

- “Delivery Rate(s)” means such volumes as are mutually agreed to between the parties pursuant to a Transaction.

- “Designated Rating Agency” means DBRS Limited (“DBRS”), Standard & Poor’s Corporation (“S&P”) or Moody’s Investors Services, Inc. (“Moodys”), and any successors thereto.

- “Disputed Amount” means any amount that the Exposed Party or the Non-Defaulting Party, as the case may be, would be entitled to receive under the Contract, without duplication, if such amounts had not been disputed by the Non-Exposed Party or Defaulting Party, as the case may be.

- “Diversion” means the agreement by EGDI to attempt to deliver quantities of Gas to a delivery point and/or a delivery area in accordance with the delivery service obligation set forth for “diversion” or similar service in Transporter’s tariff, which attempt shall be without liability (other than liability with respect to Imbalance Charges imposed pursuant to Article 8.3 or 15.3).

- “Early Termination Date” shall have the meaning given to it in Article 14.4.

- “EGDI Nominated Volume” means the volume of Gas required to be nominated by EGDI on a Day during the term of a Transportation Exchange Services Transaction, such volume being prescribed by the terms of the applicable Transportation Exchange Services Transaction Confirmation as further defined in Article 4.4.

- “EGDI Unaccepted Volume” means the volume of Gas equal to the amount obtained by subtracting the amount of Gas accepted by EGDI at the Receipt Point from the Daily Delivered Volume.

- "Event of Default" means (i) the failure to make payment when due under the Contract, which is not remedied within two (2) Business Days after receiving Notice thereof (except for a failure to pay an Accelerated Payment Invoice which shall immediately constitute an Event of Default); (ii) in respect of a party or its Credit Support Provider, if applicable, the making of an assignment or any general arrangement for the benefit of creditors, the filing of a petition or otherwise commencing, authorizing, or acquiescing in the commencement of a proceeding or cause under any bankruptcy or similar law for the protection of creditors or having such petition filed or proceeding commenced against it, any bankruptcy or insolvency (however evidenced) or the inability to pay debts as they fall due; (iii) the failure to provide and maintain Performance Assurance in accordance with Article 14.1; (iv) a party (the “Non Exposed Party”) experiences a Material Adverse Change, provided that a Material Adverse Change shall not be considered as such if the Non-Exposed Party obtains and delivers to the other party (the "Exposed Party") Performance Assurance within three (3) Business Days from the date on which the Material Adverse Change occurred (that names the Exposed Party as the beneficiary thereunder, that is maintained by the Non-Exposed Party so long as the Credit Rating applicable to it continues to be at or below the credit rating described in the definition of Material Adverse Change, and that is extended, increased or replaced in accordance with Article 14.2) in an amount no less than the Exposure Amount (calculated as if the date of the Material Adverse Change was an Early Termination Date), rounded upwards to the next $100,000; (v) a party or its Credit Support Provider, if applicable, suffering or being the subject of a default, event of default, termination event, breach or other similar condition or event (howsoever expressed) that has not been remedied within the applicable grace periods under any other agreement or instrument (including without limitation, commodity and financial derivative agreements or transactions) between a party and the other party, where the result of such event has been the termination and liquidation of transactions and the acceleration of amounts due hereunder; or (vi) the failure to perform any other material obligation under the Contract, (other than a failure to deliver or accept delivery of Gas which remedy is set forth in Articles 4.6, 5.3, 5.4, 6.3, and 6.4 or an obligation which is specifically covered in this definition as a separate Event of Default), if not remedied within five (5) Business Days after receiving Notice of such failure.

- "Exposed Party" shall have the meaning given to it in the definition of Event of Default.

- "Exposure Amount" means an amount equal to the Final Liquidation Amount, that is or would be owed by the relevant party whether or not a Notice of termination of Transactions under the Contract has been served and whether or not a Non-Performance or an Event of Default or a Potential Event of Default has occurred.

- "Failure Day" shall mean a Day on which the Non-Performing Party has failed to purchase and receive, or sell and deliver, as applicable, the greater of (i) 500 MMBtus; or (ii) 4% of the Contract Quantity to be accepted or redelivered, as applicable, on such Day, pursuant to a Transaction for Transportation Exchange Services, which failure is not excused because of the Non-Performance of the Performing Party, or by Force Majeure.

- "Final Liquidation Amount" shall have the meaning set forth in Article 14.5.b.

- "Firm" means that either party may interrupt its performance under a Transaction without liability (other than liability with respect to Imbalance Charges imposed pursuant to Article 8.3 or 15.3) only to the extent that such performance is excused by the other party's Non-Performance, by the exercise by a party of its suspension rights under Article XIV, or by Force Majeure.

- "Gas" means any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane.

- "GJ" shall mean 1 gigajoule; 1 gigajoule = 1,000,000,000 Joules. The standard conversion factor between Dekatherms and GJs is 1.055056 GJs per Dekatherm.

- "Imbalance Charges" means any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

- "Interest Rate" means the lower of: (i) if the amount payable is in United States currency, the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent (2%) per annum, compounded monthly; or, if the amount payable is in Canadian currency, the per annum rate of interest identified from time to time by TD Canada Trust, Main Branch, Calgary, Alberta, Canada as its prime lending rate charged to its most creditworthy customers for commercial loans denominated in Canadian dollars, plus two percent (2%) per annum, compounded monthly; or (ii) the maximum applicable lawful interest rate.

- "Interruptible" means that either party may interrupt its performance at any time for any reason, without liability (other than liability with respect to Imbalance Charges imposed pursuant to Article 8.3 or 15.3).

- "Letter of Credit" means an irrevocable, standby letter of credit issued by a Canadian branch office of a U.S. commercial bank or a Schedule 1 Canadian bank (which is not an Affiliate of EGDI or Customer) having a Credit Rating of at least A from S&P or A2 from Moody's, and in the event only one rating is available from either S&P or Moody's or the rating is split between S&P and Moody's, the lowest available rating will prevail.

- "Loan Balance" means, at any time during the term of a Transaction, the difference between the Maximum Loan Volume and the cumulative volumes delivered by Customer to EGDI at the Receipt Point.

- "Loan Service" means a Transactional Service whereby EGDI delivers a quantity of Gas to Customer at a Delivery Point and subsequently receives an equal quantity of Gas from Customer at a Receipt Point.

- "Market Value" of a Transaction is the net present value (applying the Present Value Discount Rate) of the product of (1) the quantity of Gas remaining under a Transaction which the parties are obligated to transact, multiplied by (2) a market price for a similar transaction considering the remaining Delivery Period and/or Redelivery Period, as applicable, the Storage Balance or Loan Balance, and Delivery Point, Redelivery Point and/or Receipt Point, as applicable; with such market price to be established by either a (i) a bona fide offer accepted by the Non-Defaulting Party from a third party in an arms-length negotiation for a replacement transaction or (ii) quotations obtained by the Non-Defaulting Party, in good faith, from three Reference Market Makers, where the arithmetic average of the quotes shall be the market price.

- "Material Adverse Change" means that the Credit Rating applicable to a party, or its Credit Support Provider, is rated by DBRS below BBB (low) stable or by S&P below BBB- stable, or by Moody's below Baa3 stable.

- "Maximum Loan Volume" means the volume of Gas to be delivered to the Delivery Point by EGDI as set forth in a Loan Services Transaction Confirmation.

- "Maximum Storage Volume" means the volume of Gas to be delivered to the Delivery Point by Customer as set forth in a Storage Service Transaction Confirmation.

- "Maximum Transportation Exchange Volume" means the aggregate of the volume of Gas to be delivered or redelivered, to either the Delivery Point or Redelivery Point, as applicable, as set forth in a Transaction Confirmation for a Transportation Exchange Service.

- "MMBtu" means one million British Thermal Units, which is equivalent to one Dekatherm.

- "Month" means the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

- "Nomination Change Period" means a reasonable period of time to change a nomination, taking into account the applicable Transporter's nomination deadlines, after receipt of an operational notice pursuant to Article 8.2 or a notification pursuant to Article 15.5, as applicable.

- "Non-Defaulting Party" shall have the meaning given to it in Article 14.4.

- "Non-Exposed Party" shall have the meaning given to it in the definition of Event of Default.

- "Non-Firm" shall include Interruptible and Diversion, as defined above.

- "Non-Performance" means the failure by a party to perform a Transactional Service(s) in accordance with the terms of the applicable Transaction, which failure is not excused by (i) the Non-Performance of the other party; (ii) the exercise by a party of its suspension rights under Article XIV; or (iii) Force Majeure.

- "Non-Performing Party" means a party in respect of which a Non-Performance has occurred. For the purpose of Article 14.6, the party failing to perform a Transactional Service shall be deemed to be the Non-Performing Party.

- "Payment Date" means the 25th day of the Month following Month of delivery.

- "Performance Assurance" means support in the form, amount and term reasonably specified by the party demanding the Performance Assurance, including, but not limited to, a Letter of Credit, a prepayment, a security interest in an asset or a performance bond or guarantee by an entity acceptable to the party demanding Performance Assurance.

- "Performing Party" means, if a Non-Performance has occurred, the party which is not the Non-Performing Party.

- "Potential Event of Default" means any event or circumstance which would, with Notice, the passage of time, or both, constitute an Event of Default.

- "Present Value Discount Rate" means with respect to any Transaction: (i) if the amount payable is in Canadian currency, the yield of Canadian Government Treasury Bills with a term closest to the time remaining in the Delivery Period and/or Redelivery Period, as applicable, plus 100 basis points; or (ii) if the amount payable is in United States currency, the "Ask Yield" interest rate for United States Government Treasury notes as quoted in the "Treasury Bonds, Notes, and Bills" section of the Wall Street Journal most recently published with a term closest to the time remaining in the Delivery Period and/or Redelivery

Period, as applicable, plus 100 basis points.

- “Price Source Disruption” shall mean with respect to the Spot Price, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Spot Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading in the relevant options contract or commodity on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) a material change in the formula for or the method of determining the Spot Price.

- "Receipt Point" means such point(s) as are mutually agreed upon between the parties as set forth in the Transaction Confirmation.

- “Receiving Transporter” means the Transporter receiving Gas at a Receipt Point, Delivery Point or Redelivery Point, as the case may be, or absent such Transporter, the Transporter delivering Gas at a Receipt Point, Delivery Point or Redelivery Point, as the case may be.

- “Redelivery Period” means the period during which redeliveries are to be made pursuant to a Transaction.

- “Redelivery Point(s)” means such points of redelivery of Gas pursuant to a Transaction.

- “Redelivery Rate(s)” means such volumes as are mutually agreed to between the parties pursuant to a Transaction.

- “Reference Market Makers” means leading dealers in the physical gas trading market or the energy swap market, selected by the Non-Defaulting Party from among dealers of the highest credit standing, which satisfy all the criteria that such party applies generally at the time in deciding whether to offer or to make an extension of credit.

- “Scheduled Gas” means the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

- "Seller" when used in the definition of "Termination Payment" refers to the party delivering or redelivering Gas, as applicable, pursuant to a Transaction.

- “Spot Price” means, if applicable, the price listed in the publication specified in Exhibit “C” under the listing applicable to the geographic location closest in proximity to the Delivery Point(s), Redelivery Point(s) or Receipt Point(s), as applicable, for the relevant Day; provided, if there is no single price published for such location for such Day other than as a result of a Price Source Disruption, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that immediately precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day. If a Price Source Disruption occurs, the parties shall negotiate in good faith to agree on a new Spot Price (or a method of determining a Spot Price) for the affected Transaction Confirmation(s). If the parties have not so agreed on or before the fifth

Business Day following the first Business Day on which the Price Source Disruption occurred or existed, then the Spot Price shall be determined in good faith by the parties based upon quotes from dealers or brokers or both in natural gas contracts as follows: Each party may obtain a maximum of two quotes to be provided (together with the identity of the dealers or brokers to permit verification) to the other party no later than 10 Business Days following the first Business Day on which the Price Source Disruption occurred or existed. These quotes shall reflect transacted prices on similar terms to the extent that such prices are available. The Spot Price for the affected Transaction Confirmation(s) shall equal a simple average of the quotes obtained and provided in accordance with this definition. If one party does not provide quotes in accordance with the foregoing, only the quotes from the other party providing same shall be used to calculate the Spot Price.

- “Storage Balance” means, at any time during the term of a Transaction for Storage Service, the difference between the Maximum Storage Volume and the cumulative volumes redelivered by EGDI to the Customer at the Redelivery Point.

- “Storage Service” means a Transactional Service whereby the Customer delivers a quantity of Gas to EGDI at a Delivery Point and subsequently receives an equal quantity of Gas from EGDI at a Redelivery Point.

- “Termination Payment” for a Transaction means the difference between the Market Value and the Contract Value as of the Early Termination Date. If the Non-Defaulting Party is Seller under that Transaction and: (i) the Market Value is greater than the Contract Value, then the Termination Payment in respect of that Transaction will be positive (gain); or (ii) if the Market Value is less than the Contract Value, the Termination Payment in respect of that Transaction will be negative (loss). If the Non-Defaulting Party is Buyer under that Transaction and: (A) the Contract Value is greater than the Market Value, the Termination Payment in respect of that Transaction will be positive (gain); or (B) if the Contract Value is less than the Market Value, the Termination Payment in respect of that Transaction will be negative (loss). Any loss with respect to a Transaction will be owed by the Defaulting Party to the Non-Defaulting Party and any gain with respect to a Transaction will be owed by the Non-Defaulting Party to the Defaulting Party.

- “Transaction” means any Transactional Service agreement effected pursuant to the Base Contract.

- “Transaction Confirmation” means the document, substantially in the form(s) of Exhibit A, Annexes A, B, or C, as applicable setting forth the terms of a Transaction.

- “Transactional Service” means a Transportation Exchange Service, Loan Service, Storage Service, or Capacity Release Service.

- “Transactional Service Fees” means the fees to be paid by the Customer to EGDI for the provision of Transactional Services, as agreed pursuant to a Transaction referenced as the “Transportation Exchange Fee”, “Loan Fee”, or “Storage Fee”, as applicable.

- "Transportation Exchange Service" means a Transactional Service whereby EGDI receives a quantity of Gas from Customer at a Receipt Point and simultaneously delivers an equal quantity of Gas to Customer at a Redelivery Point, which Receipt Point is different than the Redelivery Point.

- "Transporter" means all Gas gathering, storage or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting or storing Gas for EGDI or Customer upstream or downstream, respectively, of the Delivery Point, Redelivery Point or Receipt Point, as applicable, as agreed in a Transaction.

ARTICLE II
TERM

2.1 The Contract may be terminated on 30 days Notice, but shall remain in effect until the expiration of the latest Delivery Period or Redelivery Period, as applicable, of all Transactions. The rights of either party pursuant to Article 11.6, the obligations of either party pursuant to Article 16.10, the obligations to make payment under the Contract and the obligation of either party to indemnify the other party pursuant to this Contract shall survive the termination of this Contract.

ARTICLE III
CONTRACTING PROCEDURES

3.1 This Base Contract is intended to facilitate Transactions on a Firm or Non-Firm basis.

3.2 Any Transaction may be effected orally or electronically with the offer and acceptance constituting the valid, binding and enforceable agreement of the parties. The parties are legally bound from the time the Transaction is effected. Any such Transaction is considered a "writing" and to have been "signed". Notwithstanding the previous sentence, the parties agree that EGDI shall confirm a Transaction by sending the Customer a Transaction Confirmation by facsimile or mutually agreeable electronic means within two Business Days following the Day on which the Transaction is effected. EGDI adopts its letterhead or the like as its signature on any Transaction Confirmation and as the identification and authentication of EGDI.

3.3 If a Transaction Confirmation sent by EGDI is materially different from Customer's understanding of the agreement referred to in Article 3.2, the Customer shall give EGDI Notice clearly identifying such difference on EGDI's Transaction Confirmation and return the annotated Transaction Confirmation to EGDI by the Confirm Deadline. The failure of the Customer to so notify EGDI by the Confirm Deadline is further evidence of the agreement between the parties and constitutes the Customer's acknowledgement that the terms of the Transaction described in EGDI's Transaction Confirmation are accurate.

3.4 If a Transaction Confirmation is required pursuant to Article 3.2 and Customer does not receive a Transaction Confirmation from EGDI by the deadline set out in Article 3.2, then Customer may notify EGDI by sending its own Transaction Confirmation by the close of the Business Day following the deadline set out in Article 3.2. If a Transaction Confirmation sent by Customer is materially different from EGDI's understanding of the agreement referred to in Article 3.2, EGDI shall give Customer Notice clearly identifying such difference on Customer's Transaction Confirmation and return the annotated Transaction Confirmation to Customer by the Confirm Deadline. The failure of EGDI to so notify Customer by the Confirm Deadline is further evidence of the agreement between the parties and constitutes EGDI's acknowledgement that the terms of the Transaction described in Customer's Transaction Confirmation are accurate.

3.5 If Customer does not receive a Transaction Confirmation from EGDI by the deadline set out in Article 3.2 and Customer does not send its own Transaction Confirmation as provided for in Article 3.4, the absence of a Transaction Confirmation in respect of a particular Transaction does not negate the existence of such Transaction.

3.6 If a Transaction Confirmation contains any provisions other than those relating to the commercial terms of the Transaction which modify or supplement the Base Contract, such provisions shall not be deemed to be accepted pursuant to this Article III unless expressly agreed to in writing by both parties; provided that the foregoing shall not invalidate any Transaction agreed to by the parties.

3.7 The entire agreement between the parties shall be those provisions contained in (i) an effective Transaction Confirmation, (ii) a Transaction entered into by the parties either orally or electronically, and (iii) the Base Contract. In the event of a conflict among the foregoing, the terms shall govern in the priority listed in the preceding sentence. All Transactions are entered into in reliance on the fact that the Base Contract, each Transaction Confirmation and each Transaction constitute a single integrated agreement between the parties and the parties would not have otherwise have entered into the Base Contract or any Transaction.

3.8 Communications occurring via a telephone conversation may be recorded by either party and each party consents to same without further notice to, or consent from, the other party. Each party shall, to the extent required by applicable law, give notice to, and obtain consent from, each of its employees, contractors and other representatives who may have their communications recorded hereunder. Any recordings of communications relevant to a Transaction may be used as evidence in any legal, arbitration, or other dispute resolution procedure, and the parties hereby expressly waive all rights to, and expressly agree not to, contest or otherwise argue against such use of any recordings relevant to the disputed Transaction.

3.9 Each party shall be entitled, upon reasonable request, to access the other party's recording(s), if any, associated with a disputed Transaction.

ARTICLE IV
TRANSPORTATION EXCHANGE SERVICES

4.1 Service. Customer may request, and EGDI may provide, Transportation Exchange Services in accordance with the provisions of this Article IV.

4.2. Deliveries. The Customer shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, each Day during the term of a Transaction for Transportation Exchange Services, deliver, or cause to be delivered, on a Firm or Non-Firm basis, and EGDI shall, in the case of a Firm obligation and may, in the case of a Non-Firm obligation, accept, at the Receipt Point, such volume of Gas to be delivered in accordance with such Transaction, which volume shall be the "Customer Nominated Volume." The volume of Gas which is actually delivered to the Receipt Point shall be referred to as the "Daily Delivered Volume".

4.3 Delivered Volume Balance. At any time on any Day during the term of a Transaction, the "Delivered Volume Balance" shall be the amount obtained by subtracting the Daily Delivered Volume from the Customer Nominated Volume.

4.4 Redeliveries. Subject to Article 4.2, on receipt of confirmation from the Customer's Transporter in writing or orally of a Daily Delivered Volume, EGDI shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, in accordance with nominations given to EGDI's Transporter, deliver, or cause to be delivered, and the Customer shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, accept, a volume of Gas equal to the Daily Delivered Volume for such nomination cycle to the account of the Customer at the Redelivery Point, which volume shall be the "EGDI Nominated Volume". The volume of Gas, which is actually delivered to the Redelivery Point, shall be referred to as the "Daily Redelivered Volume".

4.5 Redelivered Volume Balance. At any time on any Day during the term of a Transaction, the "Redelivered Volume Balance" shall be the amount obtained by subtracting the Daily Redelivered Volume from the EGDI Nominated Volume.

4.6 In the event of a breach of a Firm obligation for Transportation Exchange Service, the Performing Party shall be entitled to recovery of the following for each Day that the breach occurs:

4.6.a In the case of a Firm obligation and EGDI fails to accept all or part of the Customer Nominated Volume and to the extent the Customer has otherwise performed hereunder:

(i) EGDI shall forfeit the right to the EGDI Unaccepted Volume; and

(ii) Customer shall pay EGDI an amount equal to (A) the product of (1) the EGDI Unaccepted Volume, and (2) the Spot Price minus (B) the sum of (1) any Imbalance Charges incurred by the Customer as a consequence of EGDI's failure to accept the EGDI Unaccepted Volume and (2) an administrative fee calculated as the product of (a) the EGDI Unaccepted Volume, and (b) U.S. $0.25/MMBtu.

4.6.b. In the case of a Firm obligation and EGDI fails to redeliver all or part of the EGDI Nominated Volume and to the extent the Customer has otherwise performed hereunder:

(i) The Customer shall forfeit the right to the Redelivered Volume Balance; and

(ii) EGDI shall pay the Customer an amount equal to (A) the product of (1) the Redelivered Volume Balance, and (2) the Spot Price, plus (B) the sum of (1) any Imbalance Charges incurred by the Customer as a consequence of EGDI's failure to deliver the EGDI Redelivered Volume Balance and (2) an administrative fee calculated as the product of (a) the Redelivered Volume Balance and (b) U.S. $0.25/MMBtu.

4.6.c In the case of a Firm obligation and the Customer fails to accept all or part of the EGDI Nominated Volume and to the extent EGDI has otherwise performed hereunder:

(i) The Customer shall forfeit the right to the Customer Unaccepted Volume; and

(ii) EGDI shall pay Customer an amount equal to (A) the product of (1) the Customer Unaccepted Volume, and (2) the Spot Price, minus (B) the sum of (1) any Imbalance Charges incurred by EGDI as a consequence of the Customer's failure to accept the Customer Unaccepted Volume, and (2) an administrative fee calculated as the product of (a) the Customer Unaccepted Volume, and (b) U.S. $0.25/MMBtu.

4.6.d. In the case of a Firm obligation and the Customer fails to deliver all or part of the Customer Nominated Volume and to the extent EGDI has otherwise performed hereunder:

(i) EGDI shall forfeit the right to the Delivered Volume Balance; and

(ii) Customer shall pay EGDI an amount equal to (A) the product of (1) the Delivered Volume Balance, and (2) the Spot Price, plus (B) the sum of (1) any Imbalance Charges incurred by EGDI as a consequence of the Customer's failure to deliver the Delivered Volume Balance, and (2) an administrative fee calculated as the product of (a) the Delivered Volume Balance, and (b) U.S. $0.25/MMBtu.

4.7 In addition to the rights set out in Articles IV and XIV, unless otherwise specified on the applicable Transaction Confirmation, a Performing Party shall have the right ("Termination Right") to terminate, accelerate and liquidate an Affected Transaction by providing Notice to the Non-Performing Party designating an Early Termination Date, which date shall be between 1 and 5 Business Days following the most recent Non-Performance causing the Affected Transaction, but no earlier than the effective date of the Notice, on which date the Affected Transaction shall terminate. Following the exercise of its Termination Right, the Performing Party shall calculate the Termination Payment in respect of the Affected Transaction, which amount shall be paid in accordance with Article 14.5, all as if an Early Termination Date had occurred, the Affected Transaction was the only Transaction, the Performing Party was the Non-Defaulting Party and the Non-Performing Party was the Defaulting Party. The exercise of the Termination Right shall not be deemed to be an Event of Default or similar default with respect to the Affected Transaction, any other Transactions or any other agreement between the parties. If the Performing Party fails to provide Notice to exercise its Termination Right within 5 Business Days of the occurrence of the last Non-Performance that gave rise to that Termination Right, the Termination Right shall expire, but without prejudice to any Termination Right that may subsequently arise upon the occurrence of a further Non-Performance in respect of that Transaction.

ARTICLE V
LOAN SERVICES

5.1 Service. Customer may request, and EGDI may provide, Loan Services in accordance with the provisions of this Article V.

5.2 Loan Services. EGDI shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, in accordance with nominations given by Customer, which are consistent with the Delivery Rates, deliver or cause to be delivered to Customer and Customer shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, accept at the Delivery Point such volume of Gas ("Delivered Volumes") during the Delivery Period. Customer shall, in the case of a Firm obligation and may, in the case of a Non-Firm obligation, in accordance with nominations given by EGDI, which are consistent with the Redelivery Rates, redeliver or cause to be redelivered to EGDI and EGDI shall accept, at the Redelivery Point, such volume of Gas ("Redelivered Volumes") during the Redelivery Period.

5.3 Failure to Deliver. In addition to any other remedies available to Customer hereunder, if in the case of a Firm obligation, EGDI fails to deliver Gas in accordance with Article 5.2 on any Day during the Delivery Period, then such occurrence shall constitute a default and for the purposes of this Article 5.3, the "Default Quantity" shall be the difference between the amount of Gas actually delivered on such Day and the amount of Gas that was to be delivered on that Day. Upon default, EGDI shall forthwith pay to Customer, as liquidated damages and not as a penalty, the sum of (a) any Transporter Imbalance Charges incurred by Customer, plus (b) an administrative fee of $0.10 Canadian per GJ on the Default Quantity, representing an estimate of the reasonable costs and expenses incurred by Customer (in addition to Transporter Imbalance Charges), plus (c) the product of the Default Quantity multiplied by the Spot Price for the Day or Days upon which EGDI failed to deliver the Default Quantity at the Delivery Point. For greater certainty, the applicable Transactional Service Fee will be applied.

5.4 Failure to Redeliver. In addition to any other remedies available to EGDI hereunder, if in the case of a Firm obligation, Customer fails to redeliver Gas in accordance with Article 5.2 on any Day during the Redelivery Period, then such occurrence shall constitute a default and for the purposes of this Article 5.4, the "Default Quantity" shall be the difference between the amount of Gas actually redelivered on such Day and the amount of Gas that was to be redelivered on that Day. Upon default, the Customer shall forthwith pay to EGDI, as liquidated damages and not as a penalty, the sum of (a) any Transporter Imbalance Charges incurred by EGDI, plus (b) an administrative fee of $0.10 Canadian per GJ on the Default Quantity, representing an estimate of the reasonable costs and expenses incurred by EGDI (in addition to Transporter Imbalance Charges), plus (c) the product of the Default Quantity multiplied by the Spot Price for the Day or Days upon which Customer failed to redeliver the Default Quantity at the Redelivery Point. For greater certainty, the applicable Transactional Service Fee will be applied.

ARTICLE VI
STORAGE SERVICES

6.1 Service. Customer may request, and EGDI may provide, Storage Services in accordance with the provisions of this Article VI.

6.2 Storage Services. Customer shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, in accordance with nominations given by EGDI, which are consistent with the Delivery Rates, deliver or cause to be delivered to EGDI and EGDI shall, in the case of a Firm obligation and may, in the case of a Non-Firm obligation, accept, at the Delivery Point such volume of Gas ("Delivered Volumes") during the Delivery Period. EGDI shall, in accordance with nominations given by Customer, which are consistent with the Redelivery Rates, redeliver or cause to be redelivered to Customer and Customer shall, in the case of a Firm obligation, and may, in the case of a Non-Firm obligation, accept, at the Redelivery Point, such volume of Gas ("Redelivered Volumes") during the Redelivery Period.

6.3 Failure to Receive. In addition to any other remedies available to Customer hereunder, in the case of a Firm obligation, if EGDI fails to accept the Gas in accordance with Article 6.2 on any Day during the Delivery Period, then such occurrence shall constitute a default and for the purposes of this Article 6.3, the "Default Quantity" shall be the difference between the amount of Gas actually accepted on such Day and the amount of Gas that was to be accepted on that Day. Upon default, Customer shall forthwith pay to EGDI, as liquidated damages and not as a penalty, the sum of (a) the product of the Default Quantity multiplied by the Spot Price for the Day or Days upon which EGDI failed to accept the Default Quantity at the Delivery Point, minus (b) any Transporter Imbalance Charges incurred by Customer, minus (c) an administrative fee of $0.10 Canadian per GJ on the Default Quantity, representing an estimate of the reasonable costs and expenses incurred by Customer (in addition to Transporter Imbalance Charges). For greater certainty, the applicable Transactional Service Fee will be applied.

6.4 Failure to Take. In addition to any other remedies available to EGDI hereunder, in the case of a Firm obligation, if Customer fails to accept the Gas in accordance with Article 6.2 on any Day during the Redelivery Period, then such occurrence shall constitute a default and for the purposes of this Article 6.4, the "Default Quantity" shall be the difference between the amount of Gas actually redelivered on such Day and the amount of Gas that was to be redelivered on that Day. Upon default, EGDI shall forthwith pay to Customer, as liquidated damages and not as a penalty, the sum of (a) the product of the Default Quantity multiplied by the Spot Price for the Day or Days upon which Customer failed to take the Default Quantity at the Redelivery Point, minus (b) any Transporter Imbalance Charges incurred by EGDI, minus (c) an administrative fee of $0.10 Canadian per GJ on the Default Quantity, representing an estimate of the reasonable costs and expenses incurred by EGDI (in addition to Transporter Imbalance Charges). For greater certainty, the applicable Transactional Service Fee will be applied.

ARTICLE VII
CAPACITY RELEASE SERVICES

7.1 Service. Customer may request, and EGDI may provide, Capacity Release Services in accordance with the provisions of this Article VII.

7.2 Capacity Release Services. EGDI's provision of Capacity Release Services is subject to

EGDI and Customer entering into the necessary documentation required by Transporter to effect service.

7.3 Failure to Perform. Any failure to perform by Customer with respect to a Capacity Release Service shall be between the Customer and the Transporter, and all charges, costs, or penalties charged by the Transporter shall be to the sole account of the Customer. Upon the assignment by EGDI to Customer of any of EGDI's transportation capacity required for the provision of Capacity Release Services pursuant to Article 7.2, Customer will hold EGDI harmless against any costs, liabilities or claims that EGDI may incur as a result of such assignment by EGDI of transportation capacity to Customer.

ARTICLE VIII
TRANSPORTATION, NOMINATIONS, AND IMBALANCES

8.1 The party responsible for transporting the Gas to the Receipt Point, Delivery Point or Redelivery Point, as the case may be, shall have the responsibility for delivering such Gas at a pressure sufficient to effect such delivery but not to exceed the maximum operating pressure of the Receiving Transporter, and the party responsible for taking such Gas at the Receipt Point, Delivery Point or Redelivery Point, as the case may be, shall be responsible for transporting the Gas from the Receipt Point, Delivery Point or Redelivery Point, as the case may be.

8.2 The parties shall coordinate their Gas nomination and scheduling activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior operational notice, sufficient to meet the requirements of all Transporter(s) involved in the Transaction, of the quantities of Gas to be delivered and redelivered each Day. Such operational notice may be made by any mutually agreeable means, including phone, fax and e-mail. Should either party become aware that actual deliveries at the Receipt Point, Delivery Point or Redelivery Point, as the case may be, are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

8.3 The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If EGDI or Customer receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. Imbalance Charges are payable by the party that caused such Imbalance Charges. Notwithstanding the above and the provisions of Articles 4.6, 5.3, 5.4, 6.3, 6.4, 14.3, 14.4 and 15.3, if either party had sufficient ability to avoid any Imbalance Charges through a revision of the nomination with the Transporter during the Nomination Change Period but failed to make such revision through its actions or inactions, then that party shall be deemed to have caused such Imbalance Charges. A party that pays Imbalance Charges caused by the other party (the "Responsible Party") shall be reimbursed promptly by the Responsible Party for such Imbalance Charges.

ARTICLE IX
QUALITY AND MEASUREMENT

9.1 All Gas delivered or redelivered by EGDI or Customer, as the case may be, shall meet the quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of the Contract shall be specified as one MMBtu dry, one Dekatherm dry, one GJ or one 10^3M^3. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

ARTICLE X
TAXES

10.1 Customer and EGDI shall pay or cause to be paid all taxes, fees, levies, penalties, licenses, interest or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to delivery to the Receipt Point, Delivery Point or Redelivery Point, as the case may be. If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

10.2 The Transactional Service Fees do not include any amounts payable by Customer to EGDI for the federal goods and services tax, the Quebec sales tax and any fully harmonized federal/provincial sales tax (collectively, "GST") imposed pursuant to the Excise Tax Act or any value added or sales or use tax applicable to a Transaction at the Delivery Point, Receipt Point or Redelivery Point, as applicable, under federal or provincial legislation. Customer will pay to EGDI the amount of GST payable for the Transactional Services in addition to all other amounts payable under the Contract. EGDI will account for and remit the GST paid by Customer as required by law. Customer and EGDI will provide each other with the information required to make such GST remittance or claim any corresponding input tax credits, including GST registration numbers.

10.3 In the event that any amount becomes payable as a result of a breach, modification or termination of the Contract, and if section 182 of the Excise Tax Act (Canada) applies to that payment, then the amount payable shall be increased by an amount equal to the GST percentage rate multiplied by the amount payable and the payor shall pay the increased amount.

ARTICLE XI
BILLING, PAYMENT, AND AUDIT

11.1 Invoices. EGDI shall invoice Customer by the 15th day of the Month following the Month during which the Transactional Services were provided for the amounts payable for such Transactional Services. EGDI shall provide supporting documentation acceptable in industry practice to support the amount payable.

11.2 Payment. Customer shall remit the amount due in immediately available funds, on or before the later of the Payment Date or 10 days after receipt of the invoice by Customer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. If Customer, in good faith, disputes the amount of any such statement or any part thereof, Customer will pay to EGDI such amount as it concedes to be correct; provided, however, if Customer disputes the amount due, Customer must provide supporting documentation acceptable in industry practice to support the amount paid or disputed.

11.3 Failure to Pay. If the Customer fails to remit the full amount payable when it is due, interest at the Interest Rate on the unpaid portion shall accrue from the date due until the date of payment.

11.4 Currency. Payment shall be made in the currency specified in the Transaction Confirmation.

11.5 Accelerated Payment. A Performing Party may accelerate the payment owed by the Non-Performing Party related to a Non-Performance by sending to the Non-Performing Party an invoice (an "Accelerated Payment Invoice") for the amounts due it under Articles 4.6, 5.3, 5.4, 6.3 and 6.4 respectively, setting forth the calculation thereof and a statement that pursuant to this Article 11.5 such amount is due in three (3) Business Days. If the Performing Party does not deliver an Accelerated Payment Invoice, amounts payable pursuant to Articles 4.6, 5.3, 5.4, 6.3 and 6.4 respectively, shall be invoiced and payable in accordance with Articles 11.1 and 11.2. The Non-Performing Party must pay the Accelerated Payment Invoice when due and the Non-Performing Party: (i) shall not be entitled to net amounts owed to it under this Contract by the Performing Party against its obligation to make payment on an Accelerated Payment Invoice; and (ii) shall, notwithstanding Article 11.2, pay the full amount of the Accelerated Payment Invoice despite any dispute it may have as to the amount owing thereunder. To the extent any disputed amount is subsequently resolved in favour of the Non-Performing Party, the Performing Party shall promptly pay such amount to the Non-Performing Party with accrued interest at the Interest Rate for the period from the date of dispute until the disputed amounts are paid in full.

11.6 Audit. A party shall have the right, at its own expense, upon reasonable notice and at reasonable times, to examine the books and records of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This examination right shall not be available with respect to proprietary information not directly relevant to Transactions. All invoices and billings shall be conclusively presumed final and accurate unless objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery or redelivery. All retroactive adjustments under this Article 11.6 shall be paid in full by the party owing payment within 30 days of notice and substantiation of such inaccuracy.

ARTICLE XII
TITLE, WARRANTY, AND INDEMNITY

12.1 Title. For Loan Services and Transportation Exchange Services, unless otherwise specifically agreed, title to the Gas shall pass between the parties at the Delivery Point(s), Receipt Point(s) or Redelivery Point(s), as applicable. EGDI shall have responsibility for and assume liability with respect to the Gas prior to delivery to Customer at the specified Delivery Point(s) or Receipt Point(s) or Redelivery Point(s), as applicable, and Customer shall have responsibility for and assume liability with respect to the Gas after its delivery to Customer at the Delivery Point(s) or Receipt Point(s) or Redelivery Point(s), as applicable. Customer shall have responsibility for and assume liability with respect to the Gas prior to delivery to EGDI at the specified Receipt Point(s) or Delivery Point(s) or Redelivery Point(s), as applicable, and EGDI shall have responsibility for and assume liability with respect to the Gas after its redelivery to EGDI at the Receipt Point(s) or Delivery Point(s) or Redelivery Point(s), as applicable.

12.2 Possession. For Storage Services, possession of the Gas shall pass to EGDI at the Delivery Point, but legal title to and ownership of the Gas, or possessory title as bailor of Gas, remains at all time with Customer, notwithstanding any commingling of such Gas with Gas owned by others. The Customer shall bear the full cost and expense for transporting and delivering, as well as the full and complete liability and responsibility for, such Gas to the Delivery Point and shall bear full and complete liability and responsibility for Gas that is delivered to the Delivery Point. Upon accepting custody of the Gas at the Delivery Point, EGDI shall bear full and complete liability and responsibility for Gas until it is delivered to the Redelivery Point. For certainty, the Customer has no right to the gas storage space made available to it hereunder, but only to the gas storage service, within the parameters, provided hereunder. EGDI and the Customer recognize that the gas delivered hereunder will be from a commingled stream of gas and will be carried to the Delivery Point through the facilities of one or more Gas Transporters. EGDI shall have the right to commingle gas delivered to EGDI by or for the Customer at the Delivery Point with gas owned by EGDI or any other person or persons, and EGDI shall have the right and full and absolute authority to deal in any manner with all gas delivered to it.

12.3 Warranty. For Loan Services and Transportation Exchange Services, the parties warrant they will have the right to convey and transfer good and merchantable title to all Gas delivered or redelivered hereunder and delivered and redelivered by the parties, as applicable, free and clear of all liens, encumbrances, and claims.

12.4 Indemnification. EGDI agrees to indemnify Customer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Customer. Customer agrees to indemnify EGDI and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach before title passes to EGDI.

ARTICLE XIII
NOTICES

13.1 All Transaction Confirmations, invoices, payments and other communications made pursuant to the Contract ("Notices") shall be in writing and made to the addresses for Notices specified by each party as indicated on page 1 of the Base Contract or such addresses for Notices as specified from time to time by a party in a subsequent Notice.

13.2 All Notices required hereunder may be sent by facsimile or mutually agreeable electronic means, a nationally recognized overnight courier service or hand delivered.

13.3 Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent electronically or by facsimile shall be deemed to have been received upon the sending party's receipt of confirmation of a successful transmission; if the day on which such electronic or facsimile Notice is received is not a Business Day or is after five p.m. on a Business Day, then such Notice shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party.

ARTICLE XIV
DEFAULT, NON-PERFORMANCE AND REMEDIES

14.1 If a party has reasonable grounds for insecurity regarding the payment, performance or enforceability of any obligation under the Contract, (including, without limitation, the occurrence of a Material Adverse Change in the creditworthiness of a party or its Credit Support Provider) such party may demand Performance Assurance, whether or not an Event of Default, Potential Event of Default, or Non-Performance has occurred, which Performance Assurance shall be provided by the other party by the end of the third (3rd) Business Day after the demand is received. The Performance Assurance shall not exceed the Exposure Amount, as of the date of the demand, as if all Transactions had been terminated. For the purposes of this section, reasonable grounds for insecurity may, provided all circumstances with respect to a party's creditworthiness shall be considered along with any particular event and the requesting party's normal credit practices, include, but are not limited to, a drop in a party's debt or issuer rating, a party experiences a Material Adverse Change, negative ratings watch, or material violation of loan covenants. The party demanding Performance Assurance may, until such Performance Assurance is provided, withhold any amounts owed to the other party under this Contract or any other agreement between the parties (whether or not yet due) and setoff against such withheld amount any amounts owed to the party demanding Performance Assurance under the Contract (whether or not yet due).

14.2 If the Exposure Amount exceeds, by $100,000 or more, the undrawn amount of the existing Letter of Credit, the Posting Party shall increase the amount of the Letter(s) of Credit held by the other party, within three (3) Business Days of receipt of Notice from such other party to do so, by either arranging for the amount of such Letter of Credit to be increased or arranging for an additional Letter of Credit to be delivered to such other party so that the total amount of the Letter(s) of Credit held by such other party meets the requirements of Article 14.1 calculated on the Business Day preceding the issuance of the Notice by the other party.

If the un-drawn amount of the existing Letter of Credit exceeds, by $25,000 or more, the Exposure Amount, the Posting Party shall be entitled to reduce the amount of the Letter of Credit posted by replacing the existing Letter of Credit with a Letter of Credit in an amount that meets the requirements of Article 14.1, calculated on the Business Day preceding the issuance of the Letter of Credit, and delivering that Letter of Credit to the other party within five (5) Business Days of its issuance. Such other party shall return the replaced Letter of Credit to the Posting Party within three (3) Business Days of such other party's receipt of the replacement Letter of Credit.

14.3 If a party ("Payer") does not pay the other party ("Payee") any amount owed to Payee in accordance with Article 11, then Payee may, immediately upon giving Notice to Payer, exercise any or all of the following remedies: (i) suspend its performance under all Transactions under this Contract; (ii) withhold any amounts owed to Payer under this Contract or any other agreement between the parties (whether or not yet invoiced or due) and (iii) setoff against such withheld amounts any amounts owed to Payee under this Contract (whether or not yet invoiced or due), or any other agreement. If Payee suspends its performance pursuant to this Article 14.3, Payee shall, for the period of the suspension, be entitled to damages calculated in accordance with Articles 4.6, 5.3, 5.4, 6.3 and 6.4 as applicable, with Payee treated as the Performing Party under Articles 4.6, 5.3, 5.4, 6.3 and 6.4 as applicable for the purposes of this Article 14.3 and, for the purposes of Article 8.3, Payer shall be deemed to have caused any

Imbalance Charges that accrue during the suspension period. If Payee has suspended performance under this Article 14.3 and Payer has paid all amounts owed to Payee in accordance with Article 11.1 and Payee has not designated an Early Termination Date pursuant to Article 14.4, then, promptly after such payment has been made, the parties shall resume performance under this Contract.

14.4 If an Event of Default or a Potential Event of Default occurs and is continuing with respect to a party ("Defaulting Party"), then the other party ("Non-Defaulting Party") shall have the right to exercise any or all of the following remedies: (i) if the Non-Defaulting Party has not previously suspended performance pursuant to Article 14.3, immediately upon giving Notice to the Defaulting Party, to suspend the Non-Defaulting Party's performance under all Transactions under this Contract; (ii) without Notice, to withhold or continue to withhold any amounts owed to the Defaulting Party under this Contract or any other agreement between the parties (whether or not yet invoiced or due) and set off against such withheld amounts any amounts owed the Non-Defaulting Party under this Contract (whether or not yet invoiced or due;) and (iii) to terminate, accelerate and liquidate all Transactions then outstanding or not yet commenced in accordance with the provisions of this Article XIV by providing Notice to the Defaulting Party designating an early termination date which date shall be between 1 and 20 Business Days following the Event of Default or Potential Event of Default but no earlier than the effective date of the Notice on which all such Transactions shall terminate (“Early Termination Date”). For the purposes of Article 8.3, if the Non-Defaulting Party suspends its performance under Article 14.4(i), the Defaulting Party shall be deemed to have caused any Imbalance Charges that accrue during the suspension period. If a Non-Defaulting Party has suspended performance under Article 14.3 or 14.4 and (A) the Defaulting Party remedies the Event of Default or Potential Event of Default prior to receipt of Notice from the Defaulting Party designating the Early Termination Date; or (B) the Defaulting Party does not remedy the Event of Default or Potential Event of Default and the Non-Defaulting Party has not designated an Early Termination Date within such 20 Business Days, then the parties shall promptly thereafter resume performance under this Contract.

14.5. In the event the Non-Defaulting Party provides Notice to the Defaulting Party of an Early Termination Date, the following provisions shall apply:

14.5.a. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner: (i) (the amount owed (whether or not then due or invoiced) by each party with respect to all Transactional Services between the parties under all terminated Transactions on or before the Early Termination Date and all other amounts owing by each party to the other party under this Contract (including, without limitation, any amounts owing under Articles 4.6, 5.3, 5.4, 6.3, 6.4, 8.3 and 11.1) for which payment has not yet been made by the party that owes such payment under this Contract ("Unpaid Amounts"); and (ii) the Termination Payment owed by one party to the other under each Transaction.

14.5.b. The Non-Defaulting Party shall net or aggregate, as appropriate, all (i) Termination Payments; (ii) Costs; and (iii) Unpaid Amounts, to a single liquidated amount payable by one party to the other party, (the single resulting amount being the "Net Settlement Amount").

14.5.c. At its sole option and without Notice to the Defaulting Party, the Non-Defaulting

Party may net or setoff against any Net Settlement Amount owing by the Non-Defaulting Party to the Defaulting Party any amounts owing to the Non-Defaulting Party by the Defaulting Party under any other agreement between the parties (the single resulting amount being the “Final Liquidation Amount”).

14.5.d. If any amount to be included in the Final Liquidation Amount is unascertained, the Non-Defaulting Party may estimate in good faith the amount to be included, and once it is ascertained, the Final Liquidation Amount shall be subject to further adjustment by the Non-Defaulting Party, if applicable. Interest at the Interest Rate shall accrue on any underpayments or overpayments determined to have occurred from any such adjustment from the date of the underpayment or overpayment until paid.

14.5.e. Once the Non-Defaulting Party has made the necessary calculations, it shall provide Notice to the Defaulting Party of the Final Liquidation Amount, setting forth in reasonable detail how such calculations were made together with supporting documentation. Failure to give such Notice shall not affect the validity or enforceability of the Final Liquidation Amount or give rise to any claim by the Defaulting Party against the Non-Defaulting Party for failure to give such Notice.

14.5.f. The Final Liquidation Amount shall be paid: (i) if due from the Defaulting Party to the Non-Defaulting Party within two (2) Business Days of Notice of the Final Liquidation Amount; or (ii) if due from the Non-Defaulting Party to the Defaulting Party, by the Non-Defaulting Party on the earlier of 90 Days after the Early Termination Date and the date on which it determines to its reasonable satisfaction that all affected transactions under this Contract and under any other agreement or arrangement referred to in Article 14.5.c that it wishes to include in any netting aggregations or setoff have been duly terminated. The Final Liquidation Amount, if payable by the Defaulting Party, shall be paid in full by the Defaulting Party, even if all or any part of the Final Liquidation Amount is in dispute. To the extent any Disputed Amount is subsequently resolved in favour of the Defaulting Party, the Non-Defaulting Party shall promptly pay such amount to the Defaulting Party with accrued interest at the Interest Rate for the period from the date of dispute until the Disputed Amount is paid in full.

14.5.g. Upon the designation of an Early Termination Date in accordance with Article 14.4, the Non-Defaulting Party may (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance or other support then available to the Non-Defaulting Party, and/or (ii) draw on any outstanding Letter of Credit issued for the Non-Defaulting Party's benefit, and the Non-Defaulting Party's obligation to return any surplus remaining after such obligations are satisfied in full.

14.6 In the event a party is a Non-Performing Party, the Performing Party shall have the right to, in addition to any other remedies available hereunder: (i) withhold any or all payments due the Non-Performing Party hereunder for the period of the applicable Non-Performance and net or set-off amounts due the Performing Party against such withheld amounts; (ii) during the period of the applicable Non-Performance, upon at least one (1) Business Day’s Notice, suspend its performance under any or all Transactions; and/or (iii) if the Non-Performing Party fails to pay any Accelerated Payment Invoice when due, the Performing Party may, without further Notice to the Non-Performing Party, declare an Early Termination Date with respect to the particular Transaction to which the Non-Performance relates in accordance with Article 14.4. The failure of the Performing Party to exercise any of the rights or remedies contained in this Article 14.6 shall not constitute a waiver of the Non-Performance, the requirement for payment as contemplated by Articles 4.6, 5.3, 5.4, 6.3 and/or 6.4, or any of the other rights or remedies of the Performing Party in connection herewith.

14.7 Each party reserves to itself all rights, set-offs, counterclaims, and other defences which it is or may be entitled to arising from the Contract.

ARTICLE XV
FORCE MAJEURE

15.1 Except with regard to a party's obligation to make payment due under the Contract, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure.

15.2 "Force Majeure" means any one or more of the following events which prevents or restricts delivery, receipt or redelivery, as applicable, of Gas at a Delivery Point, Receipt Point or Redelivery Point: (i) an interruption, curtailment, or pro-rationing by a Transporter, or storage operator, of firm service at the Delivery Point, Receipt Point or Redelivery Point, as applicable, regardless of the reasons therefore; or (ii) compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction.

15.3 Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary firm transportation unless primary, in-path, firm transportation is also curtailed; (ii) the party claiming Force Majeure failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship. For the purposes of Article 8.3, in the event of a Force Majeure, the Claiming Party shall be deemed to have caused any Imbalance Charges arising from the interruption or curtailment of Firm deliveries, receipts or redeliveries, as applicable due to the Force Majeure.

15.4 The Claiming Party shall make commercially reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event once it has occurred in order to resume performance; provided that the parties agree that nothing contained in this Article XV shall require: (i) the settlement of strikes, lockouts or other industrial disturbances except in the sole discretion of the party experiencing such disturbance; (ii) the extension of the Delivery Period or Redelivery Period of any Transaction; (iii) the parties to make up any quantity of Gas they would have otherwise been obligated to deliver or redeliver, as applicable, during any period when Force Majeure was validly claimed; (iv) EGDI or Customer, as applicable, to receive or redeliver Gas at a point other than the Delivery Point, Receipt Point, or Redelivery Point designated in the applicable Transaction; or (v) EGDI or Customer, as applicable, to purchase replacement Gas at a price greater than the price specified in the applicable Transaction.

15.5 The Claiming Party must provide notification to the other party. Initial notification may be given orally; provided that, as a condition precedent to claiming relief under this Article 15.5, the Claiming Party must give Notice with reasonably full particulars of the event as soon as reasonably possible. Notwithstanding Article 13, such Notice shall be deemed effective at the onset of the occurrence of the Force Majeure and the Claiming Party will be relieved of its obligation to make or accept delivery or redelivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

15.6 If a Force Majeure only partially affects the Claiming Party's ability to perform its obligations at a Delivery Point, Receipt Point or Redelivery Point, as applicable, the Claiming Party shall curtail its interruptible obligations at such Delivery Point, Receipt Point or Redelivery Point, as applicable, to the extent required to meet its Firm obligations under this Contract. If, after completely curtailing all of its interruptible obligations, the Claiming Party is still unable to meet its Firm obligations under this Contract, the Claiming Party shall, to the extent permitted by the applicable Transporter(s), reduce its Firm obligations under this Contract by the same percentage that all of its other firm obligations at the Delivery Point, Receipt Point or Redelivery Point, as applicable, are reduced, without regard to the price paid under any transaction between the Claiming Party and the other firm customers or suppliers, as applicable, of the Claiming Party.

ARTICLE XVI
MISCELLANEOUS PROVISIONS

16.1 The Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of the Contract shall run for the full term of the Contract. No assignment of the Contract, in whole or in part, will be made without the prior written consent of the non-assigning party, which consent will not be unreasonably withheld or delayed; provided, either party may transfer its interest to any parent or Affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any transfer and assumption, the transferor shall not be relieved of nor discharged from any obligations hereunder without the written consent of the non-assigning party.

16.2 If any provision in the Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of the Contract.

16.3 No waiver of any breach of the Contract shall be held to be a waiver of any other or subsequent breach.

16.4 The Contract sets forth all understandings between the parties respecting each Transaction, and any prior contracts, understandings, and representations, whether oral or written, relating to such Transactions are merged into and superseded by this Contract. The Contract may be amended only by a writing executed by both parties.

16.5 The interpretation and performance of this Contract shall be governed by the laws of the Province of Alberta, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction, and the parties submit and attorn to the exclusive jurisdiction of the courts of the Province of Alberta (including all appellate courts therein and therefrom) to determine any disputes. Each party irrevocably waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Contract.

16.6 The Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, State, Province, or local government authority having jurisdiction over the parties, their facilities, or Gas supply, or the Contract.

16.7 There is no third party beneficiary to the Contract.

16.8 Each party to this Contract represents and warrants to the other party that it has full and complete authority to enter into and perform this Contract and that this is a valid and binding agreement enforceable against it in accordance with its terms. Each person who executes the Contract on behalf of either party represents and warrants that they have full and complete authority to do so and that such party will be bound thereby.

16.9 For currency conversions required under the Contract, to convert Canadian or United States currency to the other, the parties shall use the average of the Bank of Canada posted noon spot exchange rates as quoted for each Day during the Month during which Gas was, or was obligated to be, delivered and received, or redelivered and received, as applicable.

16.10 Neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any Transaction, this Contract, or any information obtained pursuant to Article 11.6, to a third party (other than the Affiliates, employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have a need to know and have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract, (iii) to the extent necessary to implement any Transaction, or (iv) to the extent such information is delivered to such third party for the sole purpose of calculation a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any Transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. In accordance with and subject to Article 17, the parties shall be entitled to all remedies available at law or in equity, including, without limitation, injunctive remedies, to enforce, or seek relief in connection with this confidentiality obligation. The confidentiality obligation set forth in this Article 16.10 shall remain in full force and effect until the later of: (A) one year following termination of this Contract, or (b) two years following receipt of information obtained pursuant to Article 11.6.

In the event that disclosure is required in order to comply with any applicable law, order, regulation or exchange rule, the party subject to such requirement may disclose the relevant information to the extent so required, but shall promptly notify the other party, prior to disclosure, and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

16.11 It is the intention of the parties that this Contract, and any guarantee of a party's liabilities under this Contract shall each constitute an "eligible financial contract" within the meaning of the Bankruptcy and Insolvency Act (Canada) and the Companies Creditors Arrangements Act (Canada), and other similar Canadian insolvency legislation, and in that regard, each party represents and warrants to the other party (and such representation and warranty shall be deemed to be repeated at the time each Transaction is entered into) that: (i) its business consists, in whole or in part, of entering into "eligible financial contracts" for the purposes of managing its financial risk arising out of commodity price fluctuations; (ii) it is entering into each Transaction in connection with the management of its financial risk arising out of commodity price fluctuations; (iii) Gas is a fungible commodity which trades in a liquid and volatile market; and (iv) to the extent any Transaction shall constitute a “physical commodity contract” or an “over-the-counter-trade” pursuant to the *Securities Act* (Alberta) or a “commodity contract” or an “OTC derivative” pursuant to the *Securities Act* (British Columbia), it is a “qualified party” within the meaning of the Alberta Securities Commission Blanket Order BOR#91-505 and a “Qualified Party” within the meaning of paragraph 1.1. of the British Columbia Securities Commission Blanket Order BOR #91-501 (as each may be amended, restated or replaced from time to time), and that it is similarly qualified pursuant to any equivalent or analogous law, order or enactment of any other jurisdiction that may have application to such Transaction.

16.12 Any original executed Contract, Transaction Confirmation, invoice or other related document may be photocopied and stored on computer tapes and disks (an “Image”). An Image, if introduced as evidence on paper, documents received by facsimile machine or photocopies, if introduced as evidence on paper, the recordings of communications, if introduced as evidence in their original form or as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the parties to the same extent and under the same conditions as business records maintained in documentary form. Neither party shall object under any rule of evidence to the admissibility of the recordings, Images, photocopies, or facsimiles (or photocopies of the transcription of the recordings, Images or facsimiles) on the basis that such were not originated or maintained in documentary form.

16.13 The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

ARTICLE XVII
LIMITATIONS

17.1 Except as set forth herein, there is no warranty of merchantability or fitness for a particular purpose, and any and all implied warranties are disclaimed. For breach of any provision for which an express remedy or measure of damages is provided, such express remedy or measure of damages shall be the sole and exclusive remedy, a party’s liability hereunder shall be limited as set forth in such provision, and all other remedies or damages at law or in equity are waived. If no remedy or measure of damages is expressly provided herein or in a Transaction, a party’s liability shall be limited to direct actual damages only, such direct actual damages shall be the sole and exclusive remedy, and all other remedies or damages at law or in equity are waived. Unless expressly herein provided, neither party shall be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise. It is the intent of the parties that the limitations herein imposed on remedies and the measure of damages be without regard to the cause or causes related thereto, including the negligence of any party, whether such negligence be sole, joint or concurrent, or active or passive. To the extent any damages required to be paid hereunder are liquidated, the parties acknowledge that the damages are difficult or impossible to determine, or otherwise

obtaining an adequate remedy is inconvenient and the damages calculated hereunder constitute a reasonable approximation of the harm or loss.

IN WITNESS WHEREOF, this Contract has been executed as of the date first above written.

ENBRIDGE GAS DISTRIBUTION INC.		**[CUSTOMER]**	
Per:	______________________	Per:	______________________
Title:	______________________	Title:	______________________
Per:	______________________	Per:	______________________
Title:	______________________	Title:	______________________

Enbridge Gas Distribution Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, Alberta, T2P 3L8
Canada
www.enbridge.com

TRANSPORTATION EXCHANGE SERVICE TRANSACTION CONFIRMATION

Date: **Transaction No.:**

(“**Customer**”)

Attention:

Phone No.: **Fax No.:**

This Transaction Confirmation confirms the binding agreement reached between the parties on <DATE> regarding the Transportation Exchange on the terms and conditions set forth below. This Transaction Confirmation forms part of and is incorporated by reference into the Transactional Services Contract between the parties.

A. GENERAL:

Term:	Start Date:
	End Date:
Maximum Transportation Exchange Volume:	• MMBtu/GJs
Transportation Exchange Fees:	a one-time demand fee of $0.00 U.S./Cdn. Dollars ($0.00 U.S./Cdn. per MMBtu/GJ x • MMBtus/GJs); plus
	a transportation exchange fee of $0.00 U.S./Cdn. per MMBtu/GJ for gas (delivered/redelivered) at the (Delivery/Receipt) Point; plus
	all taxes applicable to all of the foregoing fees.
	Exchange Fees to be payable by: Customer/EGDI

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

Other Terms:	Schedule “A” - Special Provisions (if applicable)

B. DELIVERIES:

Receipt Point:	• (as defined in TCPL's tariff as approved by the National Energy Board) OR • (as defined in Union's rates schedules as approved by the Ontario Energy Board)
Customer’s Transporter:	Union/TCPL
Delivery Rates:	
Delivery Service Level:	Firm/Non-Firm

C. REDELIVERIES:

Redelivery Point:	• (as defined in TCPL's tariff as approved by the National Energy Board) OR • (as defined in Union's rates schedules as approved by the Ontario Energy Board)
EGDI’s Transporter:	Union/TCPL
Redelivery Service Level:	Firm/Non-Firm

EGDI		CUSTOMER
____________________	Signature	____________________
____________________	Name	____________________
____________________	Title	____________________
____________________	Phone	____________________
____________________	Fax	____________________

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

____________________________ Date ___________________________________

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

Enbridge Gas Distribution Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, Alberta, T2P 3L8
Canada
www.enbridge.com

LOAN SERVICE TRANSACTION CONFIRMATION

Date: **Transaction No.:**

(“**Customer**”)

Attention:

Phone No.: **Fax No.:**

This Transaction Confirmation confirms the binding agreement reached between the parties on <DATE> regarding the Loan service on the terms and conditions set forth below. This Transaction Confirmation forms part of and is incorporated by reference into the Transactional Services Contract between the parties.

A. GENERAL:

Term: Start Date: •

End Date: •

Loan Fees: a one-time demand fee of $0.00 U.S./Cdn. Dollars ($0.00 U.S./Cdn. per MMBtu/GJ x • MMBtus/GJs); plus

a loan fee of $0.00 U.S./Cdn. per MMBtu/GJ for gas (delivered/redelivered) at the (Delivery/Redelivery) Point; plus

all taxes applicable to all of the foregoing fees.

Loan Fees to be payable by: Customer/EGDI

Maximum Loan Volume: • MMBtu/GJs

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

Other Terms:	Schedule "A" – Special Provisions (if applicable)

B. DELIVERIES:

Delivery Rate:	• MMBtu/GJ per day
Delivery Period:	Start Date: •
	End Date: •
Delivery Point:	• (as defined in TCPL tariff as approved by the NEB)
	OR
	• (as defined in Union's Rate Schedule as approved by the OEB)
Delivery Service Level:	Firm/Non-Firm

C. REDELIVERIES:

Redelivery Rate:	• MMBtu/GJ per day
Redelivery Period:	Start Date: •
	End Date: •
Redelivery Point:	• (as defined in TCPL tariff as approved by the NEB)
	OR
	• (as defined in Union's Rate Schedule as approved by the OEB)
Redelivery Service Level:	Firm/Non-Firm

EGDI		CUSTOMER
____________________	Signature	____________________
____________________	Name	____________________
____________________	Title	____________________
____________________	Phone	____________________
____________________	Fax	____________________
____________________	Date	____________________

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

Enbridge Gas Distribution Inc.
3000 Fifth Avenue Place
425 – 1st Street S.W.
Calgary, Alberta, T2P 3L8
Canada
www.enbridge.com

ENBRIDGE

STORAGE SERVICE TRANSACTION CONFIRMATION

Date: **Transaction No.:**

(“**Customer**”)

Attention:

Phone No.: **Fax No.:**

This Transaction Confirmation confirms the binding agreement reached between the parties on <DATE> regarding the Storage service on the terms and conditions set forth below. This Transaction Confirmation forms part of and is incorporated by reference into the Transactional Services Agreement between the parties.

A. GENERAL:

Term:	Start Date: • End Date: •
Storage Fees:	a one-time demand fee of $0.00 U.S./Cdn. Dollars ($0.00 U.S./Cdn. per MMBtu/GJ x • MMBtus/GJs); plus a storage fee of $0.00 U.S./Cdn. per MMBtu/GJ for gas (delivered/redelivered) at the (Delivery/Redelivery) Point; plus all taxes applicable to all of the foregoing fees. Storage Fees to be payable by: Customer/EGDI
Maximum Storage Volume:	• MMBtu/GJs
Other Terms:	Schedule “A” – Special Provisions (if applicable)

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

B. DELIVERIES:

Delivery Rate:	• MMBtu/GJ per day
Delivery Period:	Start Date: •
	End Date: •
Delivery Point:	• (as defined in TCPL tariff as approved by the NEB)
	OR
	• (as defined in Union's Rate Schedule as approved by the OEB)
Delivery Service Level:	Firm/Non-Firm

C. REDELIVERIES:

Redelivery Rate:	• MMBtu/GJ per day
Redelivery Period:	Start Date: •
	End Date: •
Redelivery Point:	• (as defined in TCPL tariff as approved by the NEB)
	OR
	• (as defined in Union's Rate Schedule as approved by the OEB)
Redelivery Service Level:	Firm/Non-Firm

EGDI		CUSTOMER
____________________	Signature	____________________
____________________	Name	____________________
____________________	Title	____________________
____________________	Phone	____________________
____________________	Fax	____________________
____________________	Date	____________________

Enbridge Gas Distribution Inc. adopts its letter as its signature with respect to this Transaction Confirmation. Any objection of Customer to this Transaction Confirmation must be made in writing to Enbridge Gas Distribution Inc. on the second Business Day following the Business Day a Transaction Confirmation is received; provided, if the Transaction Confirmation is received after 5:00 p.m. in the receiving party’s time zone, it shall be deemed received at the opening of the next Business Day.

U.S. Banking Information

ENBRIDGE GAS DISTRIBUTION INC.	CUSTOMER

Bank: Bank of America N.T. & S.A. – New York

ABA No.: 026009593

Account No.: 6550826336

For Further Credit To: TD Canada Trust

Transit No.: 10202

Account No.: 0690-7361484

Canadian Banking Information

ENBRIDGE GAS DISTRIBUTION INC.	CUSTOMER

Bank: TD Canada Trust

Bank Code: 004

Transit No.: 10202

Account No.: 0690-5248209

SPOT PRICE PUBLICATION LISTING BY DELIVERY POINT, RECEIPT POINT OR REDELIVERY POINT, AS APPLICABLE

Delivery Points, Receipt Points or Redelivery Points, as applicable	**Index Publications**
AECO C & N.I.T.	Canadian Gas Price Reporter
Alberta Plantgate	Canadian Gas Price Reporter
Bayhurst 1	Canadian Gas Price Reporter
Bayhurst 11 Chippawa	Canadian Gas Price Reporter NGX
Dawn	NGX
Empress	Canadian Gas Price Reporter
Huntington	Gas Daily (*NW Sumas Index*)
Iroquois	Gas Daily
Kingsgate	Gas Daily
Niagara Parkway	Gas Daily NGX
Success	Canadian Gas Price Reporter
TransGas Energy Pool	Canadian Gas Price Reporter
WEI Station 2	Gas Daily

BOARD STAFF INTERROGATORY #7

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/page 14 of 21 para 28

Preamble:
In paragraph 28, the evidence states:

"In the summer, as discussed previously, EGD continues to operate its long haul contracts at 100% load factor and injects the amount in excess of customer demand on the day into storage for use in the following winter. Utilizing these contracts at 100% load factor means a characteristic of these contracts known as FT-RAM credits are not available to EGD."

(i) Given the statement above that FT-RAM credits are not available to EGD, please explain why the FT-RAM credit revenue lines appear on ExC/T1/S6/ Appendix D.

(ii) Were FT-RAM credits used in any way in the derivation of the amounts recorded in the 2012 TSDA? Please explain.

RESPONSE

i) The purpose of Appendix D was to provide the detailed calculations to support the information provided in Table 4 on page 20 of the evidence (Exhibit C, Tab1, Schedule 6). Option 4 was meant to provide the potential gas cost savings if EGD were to assume that if instead of entering into a Capacity Release Exchange with a third party it instead left the capacity empty and took advantage of the FT RAM credits itself. As described at Exhibit C, Tab 1 Schedule 6, page 19, para.37, the premise behind this option is EGD would generate savings by intentionally leaving the FT capacity empty thereby generating FT RAM credits and using those credits to offset IT Transportation costs. Therefore, in order to do that calculation it was necessary to calculate the FT RAM credits that would have been available under that assumption.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

ii) EGD itself did not generate any FT RAM credits in 2012 however, as described at Exhibit C, Tab 1 Schedule 6, page 14, para.28 the way that a Capacity Release Exchange provides value to a marketer is if the marketer leaves the capacity empty and takes advantage of FT RAM credits. This is what provides value to that third party and it is this value that EGD then can share with the counterparty generating additional revenue as can be seen in Table 4 of the evidence mentioned above.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/page 17 of 21 para 33

Preamble:
In paragraph 33, the evidence states that:

"The point of departure between this evidence and the EB-2012-0055 Decision is with regard to the third element of transactional services, temporarily surplus capacity. The Board stated "The Board notes that in a capacity release, the gas purchased by Enbridge at Empress is required to serve its customers." In fact, the transportation used to complete capacity release exchange transactions is temporarily surplus capacity as it is not required to meet the demand of its customers on the day."
Please explain the context of "temporarily surplus" capacity on the day (in the above excerpt) and contrast that with what was meant in paragraph 30 on page 15 where the evidence refers to EGD entering into capacity release exchanges "for the entire summer"?

RESPONSE

Before a Base Exchange is entered into on a particular day an examination of the difference between the expected demand on that day vs the FT capacity being delivered on that day must be made. This is an examination that can take place each day throughout the summer. A Capacity Release Exchange is essentially a series of daily exchanges that still require an examination of the difference between the expected demand vs the FT capacity being delivered but instead of for a day it is for a period. It is still however, temporarily surplus capacity as the capacity involved is to meet winter and peak day demand.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/

Please file the page from the Board's Order in the EB-2011-0277 proceeding that sets out the accounting treatment details for amounts to be recorded in the 2012 TSDA (Accounting Treatment For a Transactional Services Deferral Account). Was this accounting treatment and sharing mechanism the result of a negotiated settlement?

RESPONSE

The Board Approved accounting treatment for items and amounts to be recorded in the 2012 TSDA is provided as pages 2 to 4 of this response.

The Board Approved the EB-2011-0277 Settlement Agreement including the proposed scope for the 2012 TSDA.

Witnesses: K. Culbert
J. LeBlanc
D. Small

ACCOUNTING TREATMENT FOR A
TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
("2012 TSDA")

For the 2012 Fiscal Year

(January 1, 2012 to December 31, 2012)

The purpose of the 2012 TSDA is to record the ratepayer share of the net revenue, from transportation and storage related transactional services, in excess of the $8.0 million ratepayer guarantee and the operation and maintenance costs associated with storage related transactional services.

As determined in the NGEIR Decision with Reasons (EB-2005-0551), there is a distinction, and differing sharing mechanisms, associated with transportation related and storage related transactional services. Net transportation related transactional services revenue will employ a 75:25 sharing mechanism between the Company's ratepayers and shareholders, but net storage related transactional services revenue will employ a 90:10 sharing mechanism between ratepayers and shareholders.

Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.

In EB-2005-0001, the Board determined that the operating and maintenance expenses (O&M) such as salaries, benefits, promotion, legal fees, etc. are properly recovered from ratepayers through rates outside of the TS sharing mechanism. This methodology remains in effect for O&M related to transportation related transactional services, but no longer applies to O&M related to storage related transactional services. The NGEIR Decision with Reasons (EB-2005-0551) determined that incremental O&M related to providing storage related transactional services will now be applied against the corresponding net revenues.

Witnesses: K. Culbert
J. LeBlanc
D. Small

Simple interest is to be calculated on the opening monthly balance of the 2012 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2012 TSDA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Witnesses: K. Culbert
J. LeBlanc
D. Small

<u>Accounting Entries</u>

1. To record Transactional Services revenues and costs:

Debit/Credit:	Other Income	(Account 319. 010)
Credit/Debit:	2012 TSDA	(Account 179. 802)

To record the ratepayer portion of net revenues generated from transactional services activities in excess of the guaranteed amount, inclusive of O&M costs related to TS storage activities.

2. Allocation of costs and benefits to Transactional Services activities:

Debit/Credit:	2012 TSDA	(Account 179. 802)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2012 PGVA	(Account 179. 702)

To record adjustments for direct and avoided costs related to transactional services activities between the 2012 PGVA and 2012 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

3. Interest accrual:

Debit:	Interest Expense	(Account 323. 000)
Credit:	2012 TSDA - Interest Payable	(Account 179. 812)

To record simple interest on the opening monthly balance of the 2012 TSDA using the Board Approved EB-2006-0117 interest rate methodology.

Witnesses: K. Culbert
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #10

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/

Has EGD ever assigned transportation capacity on a long-term basis (i.e. 12 months or more) ? What is the maximum length of time EGD has ever assigned capacity and in what years did that occur? What was the maximum length of assigned capacity in 2012?

RESPONSE

With the exception of assignments of transportation capacity to Direct Purchase customers EGD has never assigned any transportation capacity for 12 months or more. EGD began assigning a small portion of its short haul TCPL Dawn to CDA capacity and TCPL Dawn to EDA capacity in April of 2008 for the April to October period. A similar practice was done in the April to October period in 2009, 2010, 2011 and 2012. Capacity Release Exchanges began in April of 2009 and similar to the short haul assignments are often for the April to October period.

Appendix C of the evidence filed at Exhibit C, Tab 1, Schedule 6, Appendix C provides a monthly breakdown of EGD's contracted capacity and the level of capacity released for the period April 2012 to November 2012. The maximum length of an assignment in 2012 was from April to October. Various other terms included May to September, May to October, October only and November only.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #11

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/

Did any transactional firm service activity in 2012 result in a failure on the part of the utility to provide full gas service to any Enbridge customer?

RESPONSE

No. Service to Enbridge customers was not impacted by any transactional service activity in 2012 or in any previous year.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #12

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExC/T1/S6/

Did any transactional service activity in 2012 result in an alteration to the Gas Supply Plan that in any way resulted in higher natural gas and/or transportation costs to customers than would otherwise be the case?

RESPONSE

No Transactional Service activity in 2012 or in any prior year resulted in higher natural gas and/or transportation costs to the customer.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #13

INTERROGATORY

ISSUE 2: Is the amount proposed to be cleared in the 2012 Transactional Services deferral account appropriate?

Ref: ExD - Reference Material

Please file the Annual Information Form for Enbridge Gas Distribution Inc. for the year ended December 31, 2012.

RESPONSE

Please see attached Annual Information Form.

Witness: B. Yuzwa

ENBRIDGE GAS DISTRIBUTION INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2012

February 14, 2013

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) for Enbridge Gas Distribution Inc. (Enbridge Gas Distribution or the Company) is given at or for the year ended December 31, 2012. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with United States generally accepted accounting principles (U.S. GAAP).

The Company's Management's Discussion and Analysis (MD&A), dated February 14, 2013, and the Company's Audited Consolidated Financial Statements, dated February 14, 2013, as at and for the year ended December 31, 2012 are incorporated by reference into this AIF and can be found on SEDAR at www.sedar.com.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this AIF to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.

Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, natural gas prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this AIF and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this AIF or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

CORPORATE STRUCTURE

Enbridge Gas Distribution was incorporated in 1848 by Special Act, II Victoria Cap. XIV, of the Province of Canada. By letters patent dated September 30, 1954, Enbridge Gas Distribution was continued under the Corporations Act, 1953 (Ontario) and is now subject to the Business Corporations Act (Ontario). The Company changed its name from The Consumers' Gas Company Ltd. to Enbridge Gas Distribution Inc. on July 25, 2002.

Enbridge Gas Distribution's head office and registered office are located at 500 Consumers Road, Toronto, Ontario, M2J 1P8.

Enbridge Gas Distribution is an indirect wholly owned subsidiary of Enbridge Inc. (Enbridge). Enbridge Energy Distribution Inc., itself an indirect wholly owned subsidiary of Enbridge, owns all of the issued and outstanding common shares of Enbridge Gas Distribution.

GENERAL DEVELOPMENT OF THE BUSINESS

The Company was incorporated in 1848 to provide manufactured coal gas for lighting to customers in the City of Toronto. By 1948, Enbridge Gas Distribution was serving 180,000 customers.

Natural gas was introduced to Ontario in the 1950s, replacing manufactured coal gas. Natural gas was first imported from the United States and later shipped from Alberta via the facilities of TransCanada PipeLines Limited (TransCanada). During the same period, the Company also expanded service to the Niagara Peninsula, Ottawa and Peterborough areas through acquisitions. In the 1960s, St. Lawrence Gas Company, Inc. (St. Lawrence), a wholly owned subsidiary of Enbridge Gas Distribution, began delivering Canadian natural gas to customers in northern New York State.

The 1970s and 1980s were periods of significant growth for Enbridge Gas Distribution. By 1989, the Company was serving one million customers. Growth during this period resulted from the widening of the price advantage of natural gas over oil and electricity, the expansion of population and industry in the Company's franchise area, various government programs promoting natural gas usage, natural gas' environmental and supply advantages and the Company's marketing efforts. This growth continued in the 1990s, with the addition of more than 480,000 customers during the decade. Customer additions between fiscal 2010 and fiscal 2012 averaged approximately 36,000 customers per year.

Enbridge Gas Distribution is a rate-regulated natural gas distribution utility now serving over 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and the surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves Massena, Ogdensburg, Potsdam and surrounding areas in northern New York State through St. Lawrence.

The Company also owns and operates unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

The utility business is conducted under statutes and municipal by-laws which grant the right to operate in the areas served. The utility operations of the Company and St. Lawrence are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission, respectively.

As at December 31, 2012, the Company owned and operated a network of approximately 36,000 kilometres of mains (2011 and 2010 - approximately 35,000 kilometres) for the transportation and distribution of natural gas, as well as the service pipes to transfer natural gas from mains to meters on customers' premises.

THREE-YEAR HISTORY

WEATHER
The Company operates in a seasonal industry and earnings vary significantly according to weather patterns. Periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather.

(Warmer)/colder than normal weather affected earnings in the past three years as follows:

Year Ended December 31,	**2012**	2011	2010
(millions of Canadian dollars) After-Tax Earnings Increase/(Decrease)	**(23)**	1	(12)

NATURAL GAS PRICES
Lower natural gas market prices result in a lower OEB approved charge to customers for the natural gas commodity. While lower natural gas commodity charges to customers result in lower revenues, there is no corresponding impact on the Company's earnings, since the cost of natural gas is flowed through to customers at cost. The Company does not earn a margin on the sale of natural gas.

REGULATORY ENVIRONMENT

Rates for 2013 have been set on a Cost of Service basis pursuant to a settlement agreement approved by the OEB in November 2012. See *Business Outlook – 2013 Cost of Service Rate Application*.

Incentive Regulation (IR)
In 2008, the OEB approved the Company's application to move to a five year IR methodology for the years 2008 through 2012. Under IR, the Company's distribution revenue requirement and associated rates were based on a formulaic approach, using prior year cumulative data with 2007 as the starting point.

The objectives of the IR Settlement Agreement were as follows:
- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

2012 IR Rate Adjustment Application
In September 2011, the Company filed an application with the OEB to adjust rates for 2012 pursuant to the Company's approved Incentive Regulation (IR) formula. The application was in accordance with the Company's historical basis of accounting. The Company applied for distribution revenue of $1,024 million, of which $1,004 million or 98% was approved on an interim basis for recovery by the OEB. The rate adjustment was effective January 1, 2012. An OEB hearing with respect to the remaining $20 million distribution revenue and related issues was held in January 2012. In May 2012, the OEB issued a decision rejecting the requested treatment and recovery of the elements which made up the remaining $20 million distribution revenue.

2011 Rate Adjustment Application
In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

2010 Rate Adjustment Application
In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received

approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

The key terms of a settlement agreement approved by the OEB in December 2008 which were in effect throughout the 2008 to 2012 IR period, are summarized as follows:

Revenue Per Customer Cap – The Settlement provided an incentive for the Company to continue growing its customer base and provided the opportunity annually to adjust distribution volumes for rate-setting to protect the Company from exposure to declining average use of natural gas by residential and small commercial customers.

Revenue Escalation – Distribution revenues were adjusted by 60% of the rate of inflation[♦] in 2008, by 55% in 2009, by 55% in 2010, by 50% in 2011 and 45% in 2012. In addition to the annual inflation adjustment, revenues grew by the annual increase in the number of customers. Based on an assumed inflation rate of 2%, the combined inflation and growth factors were forecast to result in an overall revenue escalation averaging approximately 3% per year through the term of the plan.

Earnings Sharing – To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeded the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings were shared with customers. The shareholder retained the first 100 basis points of ROE above the NROE (up to 9.66% in 2008), while earnings represented by the ROE in excess of 100 basis points above the NROE were shared equally with customers.

Adjustments – There were several cost and deferral accounts that fell outside of the revenue escalation formula, including the amount of capital invested in new power generation laterals. The Company was also allowed to apply for recovery of expenses above a defined threshold to the extent any such expenses met certain criteria set out in the IR plan.

Off Ramps – An OEB review would have been triggered if the Company's ROE on a normalized basis varied more than 300 basis points (either negatively or positively) relative to the NROE. The review, if triggered, would have determined the reasons for the variance in earnings and in such circumstances could have resulted in adjustments to the Settlement or a return to Cost of Service (COS) regulation. The review would not have had an impact on earnings for prior years. The Settlement did not preclude the Company from applying to the OEB for an increase in the embedded ROE.

CUSTOMER GROWTH

Business development is positively impacted by customer growth. Customer additions for the last three fiscal years were as follows:

Year Ended December 31,	**2012**	2011	2010
New Customer Additions[1]	**36,149**	35,862	37,023

1 New customer additions are the number of new service lines installed during the year.

Improving economic conditions, coupled with stronger than expected performance in the Residential Replacement sector led to an increase in year over year customer additions. The comparatively low price of natural gas as a fuel propelled strong results in the Residential Replacement sector.

♦ The inflation index is defined as the year-over-year change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand.

DESCRIPTION OF THE BUSINESS

CORE BUSINESS – GAS DISTRIBUTION

There are four principal interrelated aspects of the natural gas distribution business in which the Company is directly involved: Distribution Service, Gas Supply, Transportation and Storage.

Distribution Service

The Company's principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis (without a specific fixed term or fixed price contract). The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, the Company is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at the Company's option to meet seasonal or peak demands. The OEB approves rates for both contract and general services.

Customers have a choice with respect to natural gas supply. One option is a sales service option, whereby the customer purchases natural gas from the Company's supply portfolio (system supply). The Company does not earn a margin on the natural gas commodity it provides to customers. Alternatively, a natural gas user may select a direct purchase option, which is a transportation service arrangement. Under the transportation service arrangement, a customer supplies natural gas at a TransCanada Pipelines Limited (TransCanada) receipt point in western Canada or at a TransCanada delivery point in Ontario, and the Company redelivers an equivalent amount of natural gas to the customer's end-use location. As a third option, a customer may select an unbundled service arrangement. Similar to the transportation service arrangement, customers deliver their own natural gas into the Company’s distribution system, but they are responsible for balancing consumption with deliveries on a daily basis. These arrangements are billed under the OEB approved rate schedules.

Gas Supply

To acquire the necessary volume of natural gas to serve its customers, the Company maintains a diversified natural gas supply portfolio. During the year ended December 31, 2012, the Company acquired approximately 6.3 billion cubic metres of natural gas (2011 - 6.3 billion cubic metres), of which 53% (2011 - 44.1%) was acquired from western Canadian producers, 29.0% (2011 - 28.4%) was acquired from suppliers in Chicago and 18.0% (2011 - 27.5%) was acquired on a delivered basis in Ontario. The Company also transported 5.0 billion cubic metres (2011 - 5.8 billion cubic metres) of natural gas on behalf of direct purchase customers operating under a transportation service arrangement.

The Company's system supply natural gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts may be indexed to Alberta, Chicago or New York based prices.

Transportation

TransCanada transports approximately 60.0% or 6.7 billion cubic metres (2011 - 63.1% or 7.6 billion cubic metres) of the annual natural gas supply requirements of the Company’s customers. The Company has firm transportation service contracts with TransCanada for a portion of this requirement, while direct purchase customers contract directly with TransCanada or with natural gas marketers for the remainder.

The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows the Company flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. The Company forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

TransCanada’s transportation tolls, which are approved by the National Energy Board, consist of a demand component to recover fixed costs and a commodity component to recover variable costs for Firm Transportation (FT) service. An FT shipper, such as the Company, must pay the demand component regardless of the volume of natural gas that TransCanada actually transports for the FT shipper. Under the terms of TransCanada's tariff, if an FT shipper does not utilize all of its FT capacity rights, the FT shipper would nonetheless incur demand charges in respect of the unutilized portion.

In addition, the Company contracts for FT service on the pipelines of Alliance Pipeline Canada, Alliance Pipeline U.S. (collectively referred to as the Alliance network) and Vector Pipeline (Vector). The Alliance network of pipelines extends over 3,000 kilometres and runs from northeast British Columbia and northwest Alberta to the Chicago area hub, where it interconnects with the North American pipeline grid. Vector is a 560 kilometre pipeline that connects the hub facilities in the Chicago area to Dawn, Ontario. Enbridge has interests in these three pipeline facilities.

The Company relies on its long-term contracts with Union Gas Limited (Union) for transportation of natural gas from Dawn, located in south-western Ontario, to the Company's major market in the Greater Toronto Area (GTA). These contracts effectively provide the Company with access to United States sourced natural gas at Dawn. These contracts also provide transportation for natural gas received at Dawn via the Vector Pipeline as well as natural gas stored at the Company's and Union's storage pools in the Sarnia, Ontario area to the market area.

Storage

The Company's business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits the Company to take delivery of natural gas on favourable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits the Company to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to the Company's franchise area.

The Company's principal storage facilities are located in south-western Ontario, near Dawn, and have a total working capacity of approximately 3.2 billion cubic metres. Approximately 2.6 billion cubic metres of the total working capacity is available to the Company for utility operations. The Company also has storage contracts with third parties for 0.6 billion cubic metres of storage capacity.

The Company-operated storage facilities are connected to the Dawn storage and transmission hub. In the summer, natural gas is delivered to Dawn for injection into storage through the transmission facilities of Niagara Gas Transmission Limited, Union, TransCanada and Vector. In the winter, natural gas is withdrawn from storage and delivered to Dawn and transported from there to the Company's major market in the GTA through the transmission facilities of Union and TransCanada. The Company has transportation contracts with TransCanada, Vector and Union for the delivery of natural gas to and from storage.

ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT (DSM)

The Company promotes the use of natural gas as an environmentally preferred fuel and develops and delivers energy efficiency and conservation programs which enable customers to optimize their energy usage.

The Company invests in collaborative research, development, demonstration and implementation of more efficient natural gas technologies. Through Enbridge's demand side management programs, incentives are provided to customers to encourage the adoption of more energy efficient space conditioning, water heating, commercial cooking and industrial process equipment, as well as undertaking building envelope improvements.

The Company continues to work with municipalities to assist with their development of community energy plans, which are typically implemented under the Partners for Climate Protection Program, a Federation of Canadian Municipalities program.

HISTORICAL OPERATING STATISTICS

The following table presents statistics relating to the past three years of the Company's operations.

Year Ended December 31,	**2012**	2011	2010
Gas Supply and Sendout (10^6m^3)[1]			
Natural gas purchased	6,321	6,328	5,850
Gas into storage	(1,716)	(2,405)	(2,869)
Gas out of storage	1,648	2,369	2,564
Total gas sendout	6,253	6,292	5,545
Transportation of gas	4,984	5,752	6,083
	11,237	12,044	11,628
Gas sales to customers (10^6m^3)[1]	6,171	6,257	5,550
Transportation of gas (10^6m^3)[1]	4,572	5,370	5,584
Total sales (10^6m^3)[1]	10,743	11,627	11,134
Used by the Company (10^6m^3)[1]	4	4	6
Other volumetric variations (10^6m^3)[1,2]	490	413	488
	11,237	12,044	11,628
Maximum daily sendout (10^6m^3)[1]	82	88	84
Minimum daily sendout (10^6m^3)[1]	11	10	11
Average daily sendout (10^6m^3)[1]	31	33	32
Heating Degree Days[3]			
Actual	3,194	3,597	3,466
Forecast based on normal weather	3,532	3,602	3,546
Number of Active Customers[4] – end of year			
Residential	1,603,688	1,508,381	1,329,439
Commercial	125,073	120,397	110,846
Industrial	4,803	4,676	4,292
Wholesale	1	1	1
Transportation	298,307	364,027	518,689
	2,031,872	1,997,482	1,963,267
Average Revenue (per 10^3m^3) [1]			
Residential	$350	$348	$357
Commercial	$274	$294	$289
Industrial	$255	$250	$244
Wholesale	$151	$168	$177
Average Use per Residential Customer (m^3)[1]	2,320	2,572	2,507
Number of Employees – end of year	2,122	1,971	1,873

1 *m^3 = cubic metre; 10^3m^3 = thousand cubic metres; 10^6m^3 = million cubic metres; 28.369 10^6m^3 = 1 billion cubic feet (bcf)*

2 *Includes volumes for unbundled customers who deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*

3 *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the GTA.*

4 *Number of active customers is the number of natural gas consuming customers at the end of the year and includes natural gas sales and transportation service customers. As the commodity cost of natural gas is flowed through to natural gas sales customers with no mark up, the composition of customers between natural gas sales and transportation service has no material impact on the Company's earnings.*

BUSINESS OUTLOOK

2013 COST OF SERVICE RATES APPLICATION

In January 2012, the Company filed an application with the OEB to set rates for 2013 on a Cost of Service basis. The Company applied for distribution revenue of $1,104 million. The Company also applied to utilize U.S. GAAP for regulatory filing purposes. The OEB issued a preliminary decision in May 2012, approving the use of U.S. GAAP for regulatory purposes. In October 2012, the Company filed a settlement agreement reached with its interveners with the OEB relating to the Company's 2013 rate application. The settlement agreement was approved by the OEB in November 2012, which resolved all elements of the rate application except a requested increase in the deemed equity level which was heard by the OEB in November 2012. In its final decision issued on February 7, 2013, the OEB denied the Company's requested increase in the deemed equity level. The OEB concluded that a test of an increase in business or financial risk must be met before any review of a required change in deemed equity level would be considered and that the Company's risk had not increased since the last time its deemed equity level was determined.

The settlement agreement approved in November 2012 also established the right to recover other postretirement benefits (OPEB) costs of $89 million. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013. The rate order further provided for future OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

GREATER TORONTO AREA (GTA) PROJECT

In September 2012, the Company announced plans to expand its natural gas distribution system in the GTA to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $600 million, the proposed GTA Project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. The Company filed a leave to construct application with the OEB in December 2012. Subject to OEB approval, construction is targeted to start in 2014, with an expected completion date in 2015.

FRANKLIN COUNTY EXPANSION PROJECT

In July 2012, St. Lawrence received regulatory approval to expand its operations to Franklin County in New York State. The construction associated with the expansion began in August 2012 and the completion of the high pressure distribution line is slated for the fall of 2013. The total capital cost over five years, including several distribution systems, is estimated to be $41 million, with expenditures to date of approximately $14 million. The expansion is expected to add 4,400 potential customers to St. Lawrence's distribution system, which had 15,700 customers at December 31, 2012.

DISPOSITION OF AMHERSTBURG SOLAR PROJECTS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million, inclusive of deferred income tax recoveries of $10 million, were recognized as additional paid-in capital for the year-ended December 31, 2012. No gain or loss was recognized in earnings on the disposition; however, $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

TWO MILLION CUSTOMERS

During the fourth quarter of 2012, the Company reached the milestone of connecting its two millionth customer.

PRICE ADVANTAGE OF NATURAL GAS

Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue.

During 2012, natural gas in the residential market experienced, on average, a price advantage on an equivalent annual volume basis of 70% (2011 - 66%) against electricity and 73% (2011 - 69%) against domestic fuel oil.

CUSTOMER GROWTH
The Ontario franchise area remains one of the most rapidly growing regions in North America. As such, the Company will continue to grow its natural gas distribution business by adding customers to existing infrastructure and through geographic extension of the distribution system.

While customer growth results in increased distribution volumes, this increase is partially offset by the impact of lower average annual consumption – all else being equal. Lower average annual consumption typically results from customers' increased adoption of energy efficient technologies along with more energy efficient building construction.

Electricity conservation efforts have included programs to encourage fuel switching from electricity to natural gas. The Company leverages its expertise in DSM to offer fee-for-service conservation services that can include fuel switching.

ENERGY EFFICIENCY
Enbridge's 2.2 megawatt hybrid fuel cell power plant completed its fourth year of operations in 2012. The plant produces clean, low-carbon electricity from waste energy that is recovered from the pressure reduction process necessary to distribute natural gas. The Company is reviewing its pipeline network in Ontario to understand where additional applications would be appropriate.

GENERAL

EMPLOYEES
At December 31, 2012, the Company had 2,122 employees, 31% of whom are unionized. The Company's unionized employees are represented either by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. A collective agreement with CEPU expiring in 2013 was ratified by union members in April 2011. A four-year collective agreement with the IBEW is in effect, expiring in February 2015.

ENVIRONMENTAL MATTERS

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario is a signatory to the Western Climate Initiative and is currently developing proposed greenhouse gas (GHG) reduction programs with stakeholder consultations. An implementation date has not been specified. The Company continues to monitor developments and attend stakeholder consultations in Ontario.

The Company has successfully deployed a carbon data management system to help in the data capture and mandatory and voluntary reporting needs of the company. The Company continues to publicly report its GHG emissions in Ontario, which are verified by a third party, and will continue to develop internal procedures to identify operationally related GHG reductions. The Company was nominated to the 2012 Canada 200 Carbon Disclosure Leadership Index.

Former Manufactured Coal Gas Plant Sites
Information related to Former Manufactured Coal Gas Plant Sites can be found in Note 21 "Commitments and Contingencies" to the 2012 Audited Annual Consolidated Financial Statements.

RISK FACTORS

A discussion of the Company's risk factors can be found in the Company's MD&A for the year ended December 31, 2012 under the subheading "Risk Management and Financial Instruments".

SELECTED CONSOLIDATED FINANCIAL INFORMATION

(millions of Canadian dollars except per share amounts) Year Ended December 31,	**2012**	**2011**	**2010**
Total Revenue[1,2]	2,416	2,404	2,349
Earnings Applicable to the Common Shareholder[1,3]	232	191	174
Dividends Declared Per Share			
Common Shares	1.41	1.56	1.53
Preference Shares – Group 3, Series D	0.60	0.60	0.52

1 Revenues include amounts billed to customers for natural gas, which varies with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers. Earnings in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

2 Excludes revenues from discontinued operations (Project Amherstburg) of $10 million and $3 million for the years ended December 31, 2012 and 2011, respectively.

3 Includes earnings from discontinued operations (Project Amherstburg) of $4 million and $2 million for the years ended December 31, 2012 and 2011, respectively.

Since the issuer is an indirect wholly owned subsidiary of Enbridge, earnings per share is not provided.

DIVIDENDS

The declaration of dividends on the common shares is at the discretion of the Board of Directors of the Company. The Company targets to pay out approximately 90% to 100% of adjusted operating earnings as dividends. However, this policy range is subject to the Company's obligation to maintain average common equity in line with the deemed regulatory level, which may lead to a payout ratio outside of this range.

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

There are no restrictions that currently prevent the Company from paying dividends. However, in the event of liquidation, dissolution or winding-up of the Company, the preference shareholders have priority in the payment of dividends over the common shareholder. As well, restrictions in the credit or financing agreements entered into by the Company or the provisions of applicable law may preclude the payment of dividends in certain circumstances.

DESCRIPTION OF CAPITAL STRUCTURE

Information related to the Company's capital structure can be found in Note 11 "Debt" and Note 13 "Share Capital" to the 2012 Audited Annual Consolidated Financial Statements.

RATINGS

The following table sets forth the ratings assigned to the Company's Group 3, Series D preference shares, medium-term notes (MTNs) and unsecured debt, and commercial paper by DBRS Limited (DBRS) and Standard & Poor's Ratings Services (S&P).

	DBRS	**S&P**
Preference Shares, Group 3, Series D	Pfd-2 (low)	BBB
MTNs and Unsecured Debt	A	A-
Commercial Paper	R-1 (low)	A-1 (low)
Rating Outlook	Stable	Stable

Credit ratings are intended to provide investors with an independent assessment of the credit quality of an issue or issuer of securities and do not speak to the sustainability of particular securities for any particular investor. The credit ratings assigned by these ratings agencies to the securities may not reflect the potential impact of all risks on the value of the respective securities. The credit ratings accorded by these rating agencies are not recommendations to purchase, hold or sell the shares or securities and such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A description from the rating agency for each credit rating listed in the table above is set out below.

DBRS has different rating scales for short and long-term debt and preference shares. The DBRS long-term rating scale provides an opinion on the risk of default. That is, the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)". The absence of either a ''(high)'' or ''(low)'' designation indicates the rating is in the ''middle'' of the category. The Pfd-2 (low) rating assigned to the Company's preference shares is the second highest of six rating categories for preference shares. Preference shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies.

The A rating assigned to the Company's MTNs and unsecured debentures is the third highest of eight categories for long-term debt. Long-term obligations rated A are of good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than AA, and may be vulnerable to future events, but qualifying negative factors are considered manageable.

The R-1 (low) rating assigned to the Company's commercial paper is the third highest of ten rating categories and indicates good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial. Overall strength is not as favourable as with higher rating categories, and may be vulnerable to future events, but qualifying negative factors that exist are considered manageable.

S&P has different rating scales for short and long-term obligations. S&P utilizes criteria to identify the risks and assess each risk's potential impact on creditworthiness. Ratings may be modified by the addition of a plus (+) or a minus (-) sign to show the relative standing within a particular rating category. The BBB rating assigned to the Company's preference shares is the fourth highest of ten rating categories for long-term obligations. An obligor rated BBB has adequate capacity to meet its financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The A- rating assigned to the

Company's MTNs and unsecured debentures is the third highest of ten rating categories. An A rating indicates the obligor has strong capacity to meet its financial commitments, but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. The rating of A-1 (low) assigned to the Company's commercial paper is the highest of nine rating categories for short-term obligations. An obligor rated A-1 (low) has strong capacity to meet its financial commitments.

CREDIT FACILITIES

Credit facilities carried a weighted average standby fee of 0.22% per annum from January to August 2012 and 0.20% per annum from September to December 2012 on the unused portion and draws bear interest at market rates.

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option.

	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2014	**700**	**580**	**120**
St. Lawrence Gas Company, Inc.	2014	**12**	**10**	**2**
Total credit facilities		**712**	**590**	**122**

1 Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.

DIRECTORS AND OFFICERS

DIRECTORS

The following table sets forth the names of the Directors of the Company as at February 14, 2013, their municipalities of residence, their respective principal occupations within the five preceding years and the year from which they first became a Director of the Company. Each Director who is elected holds office until the next annual proceedings of shareholders or until a successor is duly elected or appointed. The Company has an Audit, Finance & Risk Committee. The Directors and Officers do not beneficially own, directly or indirectly, any voting securities of the Company or its subsidiaries.

Name and Place of Residence	**Principal Occupation During the Five Preceding Years**	**Year First Became a Director**
J. Richard Bird[(1)] Calgary, Alberta Canada	Executive Vice President, Chief Financial Officer & Corporate Development, Enbridge Inc. since January 2008.	2008
J. Lorne Braithwaite [(1)] Thornhill, Ontario Canada	Corporate Director. President and Chief Executive Officer of Build Toronto Inc. since April 2009.	2002
D. Guy Jarvis Aurora, Ontario Canada	President, Gas Distribution of Enbridge Inc. since September 2011 and President of the Company since September 2011. Senior Vice President, Investor Relations & Enterprise Risk of Enbridge Inc.	2011

Name and Place of Residence	Principal Occupation During the Five Preceding Years	Year First Became a Director
	from October 2010 to September 2011. Senior Vice President, Business Development of Enbridge Pipelines Inc. from March 2008 to October 2010. Vice President, Upstream Development, Enbridge Pipelines Inc. from December 2004 to March 2008.	
David A. Leslie (1) (2) Toronto, Ontario Canada	Corporate Director.	2007
Al Monaco (3) Calgary, Alberta Canada	President and Chief Executive Officer of Enbridge Inc. since October 2012. President of Enbridge Inc. from February 2012 to October 2012. President, Gas Pipelines, Green Energy & International of Enbridge Inc. from October 2010 to February 2012. Executive Vice President, Major Projects & Green Energy of Enbridge Inc. from March 2010 to October 2010. Executive Vice President, Major Projects of Enbridge Inc. from January 2008 to March 2010.	2012
David T. Robottom, Q.C. Calgary, Alberta Canada	Executive Vice President & Chief Legal Officer of Enbridge Inc. since October 2010. Executive Vice President, Law of Enbridge Inc. from January 2010 to October 2010. Group Vice President, Corporate Law of Enbridge Inc. from June 2006 to January 2010.	2010

1 *Member of the Audit, Finance & Risk Committee of the Board of Directors.*
2 *Mr. Leslie served as a member of the Board of Directors of Canwest Global Communications Corp. from March 26, 2007 to January 14, 2009. On October 6, 2009, Canwest Global Communications Corp. voluntarily entered into, and successfully obtained, an Order from the Ontario Superior Court of Justice (Commercial Division) relating to proceedings under the Companies' Creditors Arrangement Act.*
3 *Mr. Monaco was also a director of the Company from September 1, 2006 to January 9, 2008 when he was President of the Company.*

OFFICERS

The following table sets forth the names of the Executive Officers, their current office with the Company on February 14, 2013, their municipalities of residence and their principal occupations for the five preceding years.

Name, Position and Place of Residence	Principal Occupation During the Five Preceding Years
D. Guy Jarvis President Aurora, Ontario Canada	President, Gas Distribution of Enbridge Inc. since September 2011 and President of the Company since September 2011. Senior Vice President, Investor Relations & Enterprise Risk of Enbridge Inc. from October 2010 to September 2011. Senior Vice President, Business Development of Enbridge Pipelines Inc. from March 2008 to October 2010. Vice President, Upstream Development, Enbridge Pipelines Inc. from December 2004 to March 2008.

Name, Position and Place of Residence	Principal Occupation During the Five Preceding Years
Glenn W. Beaumont Senior Vice President, Operations Richmond Hill, Ontario Canada	Senior Vice President, Operations since October 2010. Vice President, Operations from May 2008 to October 2010. Vice President, Planning & Opportunity Development from February 2007 to May 2008. President of Enbridge Gas New Brunswick Inc. since May 2009.
James C. Grant Vice President, Business Development & Customer Strategy Aurora, Ontario Canada	Vice President, Business Development & Customer Strategy since March 2012. Vice President, Energy Supply, Storage Development & Regulatory from July 2008 to March 2012. Senior Director, Energy Supply, Storage Development & Regulatory from May 2008 to July 2008. Director, Storage Operations & Development from April 2006 to May 2008.
Narinder K. Kishinchandani Vice President, Finance Markham, Ontario Canada	Vice President, Finance since November 2010. Director, Finance & Control from December 2006 to November 2010.
James E.R. Lord Vice President, Law & Information Technology Toronto, Ontario Canada	Vice President, Law & Information Technology since April 2012. Senior Legal Counsel of Enbridge Inc. from October 2005 to April 2012.
James W. Milner Vice President, Pipeline Integrity & Engineering Thornhill, Ontario Canada	Vice President, Pipeline Integrity & Engineering since March 2012. Vice President, Pipeline Integrity & Safety from October 2010 to March 2012. Vice President, Engineering from February 2007 to October 2010.
John D. Oakley Vice President, Regional Operations Niagara Falls, Ontario Canada	Vice President, Regional Operations since October 2010. General Manager, Toronto Region from August 2008 to October 2010. General Manager, Niagara Region from November 2003 to August 2008.
Arunas J. Pleckaitis Vice President, Regulatory, Public & Government Affairs Scarborough, Ontario Canada	Vice President, Regulatory, Public & Government Affairs since March 2012. Vice President, Business Development & Customer Strategy from May 2008 to March 2012. Vice President, Operations from December 2004 to May 2008. President of Enbridge Gas New Brunswick Inc. from October 1999 to May 2009.
Malini Giridhar Vice President, Gas Supply North York, Ontario Canada	Vice President, Gas Supply since January 2013. Senior Director, Gas Supply & GTA Project from March 2012 to December 2012. Director, GTA Project from June 2011 to February 2012. Director, Energy Supply and Policy from February 2007 to May 2011.

Name, Position and Place of Residence	Principal Occupation During the Five Preceding Years
Colin K. Gruending Vice President & Treasurer Calgary, Alberta Canada	Vice President, Treasury & Tax of Enbridge Inc. since April 2011. Vice President & Controller of Enbridge Inc. from August 2005 to April 2011.

LEGAL PROCEEDINGS

Information related to the Company's legal proceedings can be found in Note 21 "Commitments and Contingencies" to the 2012 Audited Annual Consolidated Financial Statements.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of the Company, or associate or affiliate of these persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect the Company.

TRANSFER AGENTS AND REGISTRARS

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preference Shares
Computershare Investor Services Inc.
100 University Avenue, 8^{th} Floor
Toronto, Ontario, M5J 2Y1

MATERIAL CONTRACTS

The Company has not entered into any material contracts outside the ordinary course of business.

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditor's report dated February 14, 2013 in respect of the Company's consolidated financial statements as at December 31, 2012 and 2011 and for each of the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

ADDITIONAL INFORMATION

Additional information is provided in the Company's 2012 Audited Annual Consolidated Financial Statements and MD&A for the most recently completed financial year.

ADDITIONAL DISCLOSURE

VOTING SECURITIES AND PRINCIPAL HOLDERS OF VOTING SECURITIES
As of the date hereof, the only outstanding voting securities of the Company, which are 142,345,114 common shares, are held directly by Enbridge Energy Distribution Inc., an indirect wholly owned subsidiary of Enbridge. Each common share is entitled to one vote.

EXECUTIVE COMPENSATION
The Company's Statement of Executive Compensation is attached as Schedule A.

DIRECTORS AND OFFICERS OF ENBRIDGE INC.
The name, and province or state of residence of each Director or Executive Officer of Enbridge as at February 14, 2013 are as follows:

David A. Arledge, Florida	James J. Blanchard, Michigan	J. Lorne Braithwaite, Ontario
J. Herb England, Florida	Charles W. Fischer, Alberta	V. Maureen Kempston Darkes, Florida
David A. Leslie, Ontario	Al Monaco, Alberta	George K. Petty, California
Charles E. Shultz, Alberta	Dan C. Tutcher, Texas	Catherine L. Williams, Alberta
D. Guy Jarvis, Ontario	Stephen J. Wuori, Alberta	Leon A. Zupan, Texas
J. Richard Bird, Alberta	Janet A. Holder, British Columbia	Karen L. Radford, Alberta
David T. Robottom, Q.C., Alberta	Byron C. Neiles, Alberta	John K. Whelen. Alberta

SCHEDULE A

ENBRIDGE GAS DISTRIBUTION INC.
STATEMENT OF EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis describes Enbridge Inc.'s (Enbridge) executive compensation programs for 2012 that apply to the senior executives of Enbridge Gas Distribution Inc. (Enbridge Gas Distribution or the Company). The Company does not have a Compensation Committee. These programs are administered by the Human Resources & Compensation Committee (the Committee) of the Board of Directors of Enbridge (the Enbridge Board) as further described below.

The following pages describe the compensation philosophy and programs for the named executives of Enbridge Gas Distribution:

- President (Guy Jarvis);
- Vice President, Finance (Narinder (Narin) Kishinchandani); and
- the next three most highly compensated executives (Glenn Beaumont, Arunas Pleckaitis and James Grant)

In addition to his role as principal officer of the Company, Mr. Jarvis also has a strategic leadership role within Enbridge and reports to the President & Chief Executive Officer of Enbridge. The remaining executives reported in this schedule report to Mr. Jarvis and have significant responsibilities in the operating aspects of the Company.

Executive Summary

Enbridge's vision is to be the leading energy delivery company in North America. While Enbridge may be viewed as having achieved elements of this vision, enhancing and sustaining this position remains a continuing long-term pursuit. Enbridge's objective is to generate superior economic value for shareholders through investing capital in a low-risk and disciplined manner. Consistently applied, such stewardship should continue to generate attractive risk adjusted returns and, in turn, provide for consistent and growing dividend distributions and related capital appreciation. The business is capital intensive and long-term in nature. Therefore, the impact of decisions made today may not be realized until several years in the future. However, Enbridge has committed to its shareholders to deliver steady, visible and predictable results in the short-term and to operate its assets in a responsible manner.

The compensation programs at Enbridge reflect a blend of short, medium and long-term incentive awards to support its pay for performance philosophy. Operational performance is the cornerstone of assessing Enbridge's success as an organization. Relevant Enbridge corporate and business unit performance measures are established for the short-term compensation plan that focus on the critical financial, operational, safety and environmental aspects of the business unit (the Company and certain affiliates). The performance measures for the medium and long-term plans focus on overall Enbridge performance aligned with shareholder expectations for earnings growth and share price appreciation.

When assessing performance, the Committee takes into consideration both the objective pre-defined performance metrics as well as qualitative factors not captured in the formal metrics. For example, a decision to complete a certain acquisition may have long-term strategic benefits to Enbridge which may not be reflected in the short-term performance metrics. Also playing a role are a number of market-based and earnings-based key performance indicators that compare Enbridge's results to a peer group and to the broader market over a one to ten year time horizon. Therefore, the Committee's assessment of overall performance is based on a combination of the pre-defined performance metrics, the key performance indicators, as well as the qualitative aspects of management's responsibilities.

Risk Management and Executive Compensation Governance

Enbridge is committed to ensuring that the compensation programs and policies it has put in place are aligned with the long-term objectives of its shareholders. To accomplish this, Enbridge incorporates general risk management principles into all its decision making processes across the organization and regularly reviews its executive compensation programs through third party compensation consultants. This integration and review procedure helps ensure that Enbridge's programs continue to support Enbridge shareholder interests and regulatory compliance and are aligned with sound principles of risk management and governance.

The Committee oversees Enbridge's compensation programs from the perspective of whether they encourage individuals to take inappropriate or excessive risks that are reasonably likely to have a materially adverse effect on Enbridge.

Enbridge has a pay for performance philosophy that is embedded into its compensation design. Enbridge believes its mix of pay programs, its approach to goal setting, establishing targets with multiple levels of performance and evaluation of performance results assist Enbridge in mitigating excessive risk-taking that could harm its value or reward poor judgment of its executives.

The compensation programs include a combination of short, medium and long-term elements that ensure its executives are incented to consider both the immediate and long-term implications of their decisions.

Executives are compensated for their short-term performance using a combination of financial, operational, safety, environmental, customer and employee metrics that ensure a balanced perspective and are a mix of both leading and lagging indicators. Performance thresholds are established that include both minimum and maximum payouts.

Stock award programs vest over multiple years and are aligned to overall corporate performance that drives superior value to shareholders. Share ownership guidelines ensure executives have a meaningful equity stake in Enbridge to align their interests with those of shareholders.

Enbridge's insider trading and reporting guidelines prohibit directors, officers and employees from purchasing financial instruments that are designed to hedge or offset a decrease in market value of equity securities granted as compensation or held, directly or indirectly, by the director, officer or employee, including those of its business units.

The Committee has discussed the concept of risk as it relates to Enbridge's compensation programs and does not believe these programs encourage excessive or inappropriate risk taking.

Compensation Philosophy and Approach

The executive compensation philosophy and approach for the Company is set by the Committee and approved by the Enbridge Board. Enbridge's programs are designed to accomplish three objectives:
- attract and retain a highly effective executive team;
- align executives' actions with Enbridge's business strategy and the interests of Enbridge shareholders; and
- reward executives for both short, medium and long-term performance.

Benchmarking to Peers

The total compensation for Mr. Jarvis is benchmarked against a North American group of companies based on his strategic leadership role with Enbridge.

The Canadian companies are large pipeline, energy, utility and railway companies that are similar to Enbridge in size, utilizing assessments of enterprise value and revenues, and risk profile. Together they reflect the Canadian business environment within which Enbridge operates.

The US companies are mainly oil and gas pipelines and utilities, because the US energy sector is much larger and has more depth than Canada's.

Peer Group

Canada	United States
Canadian National Railway Company	Consolidated Edison, Inc.*
Canadian Natural Resources Limited*	Dominion Resources, Inc.*
Canadian Pacific Railway Limited	Duke Energy Corporation*
Cenovus Energy Inc.*	Energy Transfer Partners, L.P.*
Encana Corporation*	Enterprise Products Partners LP*
Husky Energy Inc.	Exelon Corporation*
Imperial Oil Limited*	Kinder Morgan, Inc.*
Nexen Inc.	Nextera Energy, Inc.*
Suncor Energy Inc.	Plains All American Pipeline, L.P.*
Talisman Energy Inc.	PG&E Corporation
TransCanada Corporation	PPL Corporation
	Sempra Energy
	The Southern Company*
	Spectra Energy Corp.
	The Williams Companies, Inc.

*New in 2012

How Enbridge Compares

	Canada	United States
Revenue	At 75th percentile	Above 75th percentile
Total assets	Between 50th and 75th percentile	Between 25th and 50th percentile
Number of employees	Between 50th and 75th percentile	Between 25th and 50th percentile
Market capitalization[1]	Between 50th and 75th percentile	Above 75th percentile

[1] As of September 30, 2012. All other information is based on the most recently reported data.

Setting Compensation Targets

Base pay is targeted between the median and the 75th percentile, considering the skill, competency and experience of each individual. Targets for short, medium and long-term incentives are linked to base salary levels.

Total direct compensation is targeted at the median of comparator companies in North America. The market data for Mr. Jarvis (in respect of 2012 compensation) is weighted 50% on the Canadian comparator group and 50% on the United States comparator group.

The compensation for the other named executives is managed within a framework applicable to all Senior Vice President and Vice President level positions across Enbridge. The competitiveness of this framework is based on market data extracted from third party compensation surveys. Two general surveys are used as well as energy industry specific surveys. The market data is considered from several perspectives including organization size (revenue greater than $5 billion) and industry sector (pipeline, energy and utility criteria). There is no one set of comparator companies from which the competitiveness of Enbridge's senior management programs is compared.

At Risk Compensation

When compensation is *at risk*, it means its value is based on performance and is not guaranteed. To support paying for performance, the short, medium and long-term incentives are considered at risk. In 2012, 81% of the target total direct compensation for the President and an average of 57% for the other named executives was at risk, directly aligning corporate, business unit and individual performance with the interests of shareholders.

Share Ownership

It is important for all of Enbridge's executives to have a meaningful equity stake in Enbridge, because owning Enbridge shares is a tangible way to align their interest with those of Enbridge shareholders.

Target ownership is a multiple of base salary, depending on position level, and executives are required to meet the target within four years of being appointed to the position. Shares can be acquired by making contributions to the employee savings plan, exercising stock options or by making personal investments in Enbridge common shares. Shares that an executive holds personally, or in the name of a spouse, dependent child or trust, all count toward meeting the guidelines. Stock options do not count towards meeting the guidelines.

Target and actual share ownership as of December 31, 2012:

Executive	Target ownership	Actual ownership	Meets requirements
Guy Jarvis	2x base salary	3x base salary	✓
Narin Kishinchandani	1x base salary	2x base salary	✓
Glenn Beaumont	1x base salary	2x base salary	✓
Arunas Pleckaitis	1x base salary	5x base salary	✓
James Grant	1x base salary	2x base salary	✓

Paying for Performance

Performance is the cornerstone of Enbridge's executive compensation programs. The programs are designed to motivate management to achieve the high return, low risk business model that Enbridge shareholders expect, with a focus on the long-term. The Enbridge Board reviews Enbridge's business plans over the short, medium and long-term and the Committee links the compensation programs to these timeframes. The performance of Enbridge's peer group is also considered. Together, this ensures that management is focused on delivering value to Enbridge shareholders not only in the short-term, but also continued performance in the long-term.

Annual Compensation Decision-Making Process

Each year, the President and executive team establish objectives for the upcoming year which include financial objectives as well as other key priorities. Performance relative to the objectives is reviewed at the end of the year. The President completes a self assessment and his performance is reviewed by Enbridge's President & Chief Executive Officer. In February of each year, the President & Chief Executive Officer of Enbridge recommends to the Committee the compensation of Mr. Jarvis including base salary and short-term, medium-term and long-term incentive awards. In making these decisions, the Committee is provided the award calculations based on the approved programs and competitive information compiled by the Committee's external compensation consultant.

The President follows this same process for the other named executives. Each executive completes a self assessment. Their performance during the year is documented, detailing accomplishments, areas of strength, and areas for development. In making the compensation recommendations, the performance evaluation, calculations based on approved programs, market information and internal equity with other senior executive roles across Enbridge are taken into consideration. Compensation recommendations are approved by the Committee.

The External Compensation Consultant

Since 2002, Mercer (Canada) Limited (Mercer), an independent compensation consultant, has advised the Committee on compensation matters of program design, governance, best practice and competitive market positioning. Enbridge management can also retain Mercer on compensation matters from time to time. Enbridge has retained Mercer for advice on the competitiveness and appropriateness of the compensation programs of Enbridge and its subsidiaries, as well as actuarial and benefit matters. The costs incurred by Enbridge for Mercer's services are allocated to the Company and other Enbridge subsidiaries as part of the corporate cost allocation process.

Elements of Total Compensation

Total compensation is made up of six components.

Base salary	Short-term incentive	Medium-term incentive	Long-term incentives
• annual base pay	• annual cash bonus	• performance stock units • restricted stock units	• incentive stock options • performance stock options
Retirement benefits	**Other benefits**		
• pension plans • other retirement benefits	• savings plan • perquisites • medical, dental and insurance		

Base Salary

Base salaries offer fixed compensation for performing day-to-day responsibilities, while balancing the individual's role and competency, market conditions and issues of attraction and retention.

Short-Term Incentive

The short-term incentive plan is an annual performance bonus plan, paid out in cash. It is designed to motivate management to achieve objectives tied to executing the business strategy, and to reward them according to their level of achievement for the year.

Each executive's target award and payout range reflect the level of responsibility associated with the role, as well as competitive practice, and is calculated as a percentage of base salary.

The award is paid out based on performance against a combination of Enbridge corporate, business unit and individual goals. To ensure alignment between each executive and the execution of the overall business strategy, all executives have a significant component of their incentive tied to operational business unit results as well as corporate measures. Operational results focus on the safe and reliable operation of our systems, environmental performance, the health and safety of our employee and contractor workforce, the services we provide to our customers and other employee-related metrics.

Individual performance is assessed relative to the achievement of individual objectives established at the beginning of the year tied to operational and strategic priorities.

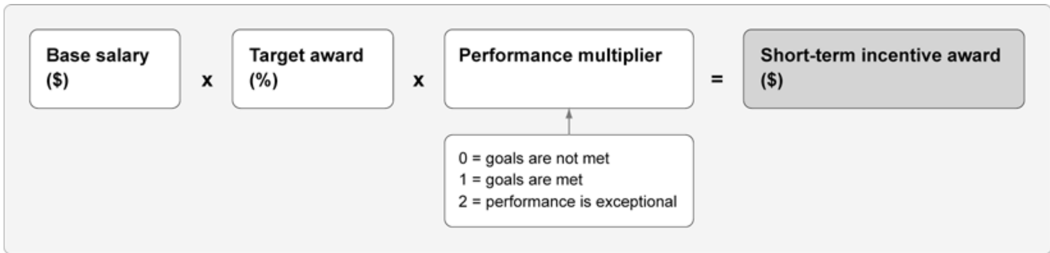
The table below shows the target short-term incentive award (as a percentage of base salary), and the percentage that each performance measure contributes to that total.

Short-Term Incentive Targets (as at December 31, 2012):

	Target award	Payout range	Performance measures		
	(as a % of base salary)		Corporate	Business unit	Individual
Guy Jarvis [1]	50%	0 – 100%	25%	50%	25%
Narin Kishinchandani	35%	0 – 70%	25%	50%	25%
Glenn Beaumont	40%	0 – 80%	25%	50%	25%
Arunas Pleckaitis	35%	0 – 70%	25%	50%	25%
James Grant	35%	0 – 70%	25%	50%	25%

[1] Mr. Jarvis' short-term incentive target increased from 40% to 50% as of August 1, 2012 to maintain market competitiveness. Mr. Jarvis' short-term incentive payment for 2012 is prorated accordingly.

Actual awards are calculated using a performance multiplier that ranges anywhere from 0 to 2.0, depending on whether the combination of goals has been met.



Using Discretion

The President & Chief Executive Officer of Enbridge can recommend to the Committee to adjust the calculated short-term incentive award for Mr. Jarvis, upwards or downwards, at his discretion. The Committee must approve the President & Chief Executive Officer's recommendations. The President of the Company may adjust the calculated awards for his direct reports at his discretion. Discretion may be exercised when the formulaic result does not fairly or accurately represent the outcomes and/or extraordinary events that occurred during the year that were not contemplated in the original measures or targets. The awards of the named executives are approved by the Committee.

The Committee can change or waive the eligibility criteria, performance measures and the levels of target and maximum awards when it believes it is reasonable to do so. In doing so, the Committee may take into consideration broader levels of performance evidenced by the key performance indicators and the environment in which the performance was achieved.

Medium and Long-Term Incentives

Enbridge's medium and long-term incentives include three plans: the performance stock unit plan, the performance stock option plan and the incentive stock option plan. These plans motivate executives to deliver strong performance and reward them for achieving earnings targets, maintaining top quartile price-to-earnings performance compared to Enbridge's peers, and appreciation in its share price over the longer-term. Prior grants are not considered in determining future grants.

Enbridge also has a restricted stock unit plan that has no performance conditions and is designed only for retention of middle management. Restricted stock units were granted to Mr. Kishinchandani before he was promoted to his current role.

The medium term and long-term incentive plans for executives all have different terms, vesting conditions and performance criteria. This mitigates the risks associated with incentive compensation programs by ensuring that executive decisions and actions are not incented to produce short-term results for individual profit. This approach benefits Enbridge shareholders and maximizes the retention value of the longer-term incentives granted to executives.

	Performance stock unit plan	Performance stock option plan	Incentive stock option plan
Term	Three years	Eight years	Ten years
Description	Phantom shares with performance conditions that affect payout.	Options to acquire Enbridge shares	Options to acquire Enbridge shares.
Frequency	Granted every year	Granted approximately every five years	Granted every year
Performance Conditions	Two performance conditions, weighted 50% each: • Enbridge earnings per share relative to a target set at the start of the term • Enbridge price to earnings performance relative to Enbridge peers	Three share price targets that must be met within a defined time period • Performance vesting weighted at 40%/40%/20%	
Vesting	Units mature in full after three years	Options vest 20% per year over five years, starting on the first anniversary of the grant date	Options vest at 25% per year over four years, starting on the first anniversary of the grant date
Payout	Paid out in cash at the end of three years based on: • the market value of an Enbridge common share at the end of three years • Enbridge performance	Participant acquires Enbridge common shares at the exercise price defined at the time of grant (fair market value)	Participant acquires Enbridge common shares at the exercise price defined at the time of grant (fair market value)

The table below shows the target amount that is granted to an executive in medium and long-term incentives each year (as a percentage of base salary) and the amount that each plan can contribute to that total.

Long-Term Incentive Targets (as at December 31, 2012):

	Target longer-term incentive grant (as % of base salary)	**Amount each plan contributes to total grant** (as % of base salary)		
		Performance stock unit plan	Incentive stock option plan	Performance stock option plan [1]
Guy Jarvis	200%	70.0%	70.0%	60%
Narin Kishinchandani	70%	21%	49%	-
Glenn Beaumont	85%	25.5%	59.5%	-
Arunas Pleckaitis	70%	21%	49%	-
James Grant	70%	21%	49%	-

Target awards for all executives except for Mr. Jarvis are adjusted by a multiplier. The multiplier is based on individual performance history, succession potential, retention considerations and market competitiveness.

Base salary ($) x **Target incentive opportunity (%)** x **Multiplier (0 - 2.25)** ÷ **Option value or share price** = **Number of options or units granted ($)**

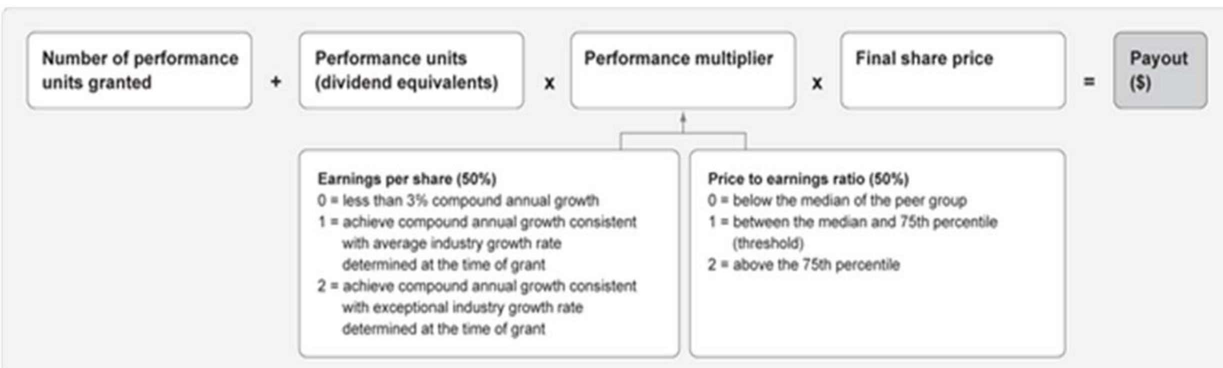
Performance Stock Units
Performance stock units give executives the opportunity to earn up to two times the value of their units when they mature after three years by achieving performance conditions. Enbridge typically grants performance stock units annually at the beginning of each year.

There are two performance measures, each weighted 50%:

- **Earnings per share (EPS):** This measure represents a commitment to Enbridge shareholders to achieve earnings that meet or exceed the industry growth rates projected at the time of grant. Executives are incented to meet or exceed the average growth rate forecasted for peer companies over a comparable time period.
- **Price-to-earnings ratio (P/E):** Enbridge uses this measure because it is a strong reflection of how Enbridge shareholders view its stock and its growth potential relative to peer companies. Enbridge compares itself against the group of companies in the table below, chosen because they are all capital market competitors, have a similar risk profile and operate in a comparable sector.

Price-to-earnings ratio comparator group	
Ameren Corporation	OGE Energy Corp.
Canadian Utilities Limited	Oneok, Inc.
Centerpoint Energy, Inc.	PG&E Corporation
Emera Incorporated	Sempra Energy
Fortis Inc.	Spectra Energy Corp.
National Fuel Gas Company	TransAlta Corporation
Nisource Inc.	TransCanada Corporation

The payout is calculated using an actual performance multiplier that ranges between 0 to 2.0, depending on whether the performance measures are met. The final share price at the end of the term is the weighted average trading price of an Enbridge common share on the Toronto Stock Exchange (TSX) or the New York Stock Exchange for the 20 days prior to the end of the term.



Performance stock options

Performance stock options give executives the opportunity to buy Enbridge common shares at the exercise price specified at the time of the grant, as long as share price targets are met by a certain date. Targets are set before the performance stock options are granted, basing them on Enbridge growth rates that represent exceptional (top quartile) performance and historical price-to-earnings ratio information for the industry.

In August 2012, Mr. Jarvis received a grant of performance stock options to cover the period of 2012 – 2016:

	A - Performance stock options granted	B - Value ($) (A × CA$4.25) [1]	C - Value (%) (B / salary on Dec 31, 2012)	D - Years	E - Annualized Value (%) (C / D)
Guy Jarvis	169,400	$719,950	180%	5	90%

[1] For more information on the value of the 2012 Performance Stock Option grant see Note 2 under the heading "Summary Compensation Table" on page A22 of this Schedule.

Incentive Stock Options
A stock option gives an employee the option to buy one Enbridge common share at some point in the future, at the exercise price defined at the time of grant.

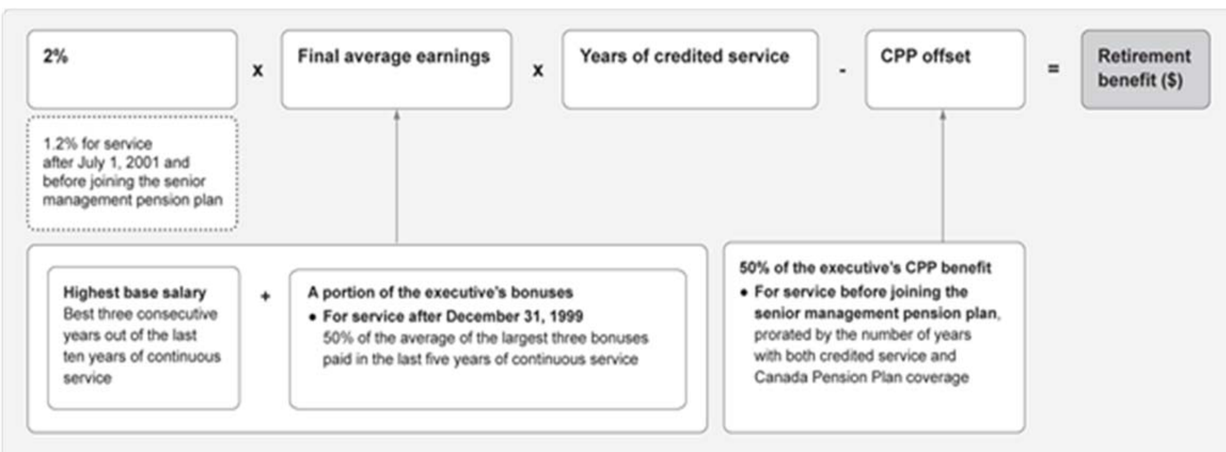
Enbridge typically grants stock options in February of each year. Options vest in equal installments over a four-year period. The maximum term of an option is 10 years, but the term can be reduced if the executive leaves the Company. See page A27 for details.

The exercise price of an option is the weighted average trading price of an Enbridge common share on the TSX for the last five trading days before the grant date. If the grant date is during a trading blackout period, Enbridge will adjust the grant date to no earlier than the sixth trading day after the trading blackout period ends. Enbridge does not backdate stock options.

Stock options may be granted to executives joining the Company. In this case, Enbridge normally grants the options on the executive's date of hire. If the hire date falls within a blackout period, the grant is delayed until after the end of the blackout period.

Retirement Benefits
As of January 1, 2000 (or the time of hire or promotion to a senior management position if after that date), the executives joined the senior management pension plan which is a non-contributory defined benefit plan that pays out an enhanced retirement income to all senior management employees. Prior to becoming members of the senior management pension plan, the executives participated in a non-contributory defined benefit or defined contribution pension plan.

Defined Benefit Plan
The table below shows how the retirement benefit payable is calculated under the defined benefit pension plans applicable to the named executives:



Some key terms of the plan:
- Retirement age: Executives can retire with an unreduced pension at age 60 or as early as age 55 with 30 years of service. Otherwise, they can retire as early as age 55 in which case their retirement benefit is reduced by 3% per year before age 60. For executives who joined the senior management pension plan after January 1, 2000, the reduction is 5% per year before age 60 for service prior to joining the senior management pension plan.
- Adjustment for inflation: Retirement benefits are indexed at 50% (55% for retirement benefits in respect of service prior to January 1, 2000) of the annual increase in the consumer price index.
- Survivor benefits: the pension is payable for the life of the member. If the member is single at retirement, 15 years of pension payments are guaranteed. If the member is married at retirement and dies before their spouse, 60% of the pension will continue to the spouse for his/her lifetime.
- Flexibility: To attract and retain executives, Enbridge can negotiate additional years of credited service or higher pension accruals, subject to approval by the Committee.

Defined Contribution Plan
The defined contribution pension plan is non-contributory and provides a level of contribution that varies with points (age plus service). None of the executives are currently participating in the defined contribution pension plan.

Other Retirement Terms
- The short-term incentive is pro-rated for service in the last year of employment.
- Unvested performance stock units are pro-rated for the period of active employment during the term of the grant. The units will continue to vest according to the terms of the plan.
- Performance stock options are pro-rated for the period of active employment. Executives can exercise performance stock options up to three years after retirement, as long as the performance criteria are met.
- Unvested incentive stock options will continue to vest. Executives can exercise stock options up to three years after retirement, or up to the date the option expires (whichever is earlier).
- The performance stock options are prorated for the period of active employment in the 5 year period starting January 1 of the year of grant. They can exercise these options until the later of three years after retirement or 30 days after the date by which the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the share price targets are met.

Other Benefits
The savings plan, perquisites and benefits plans are key elements of Enbridge's total compensation package for executives.

Savings Plan
The savings plan encourages share ownership by matching employee contributions of up to 2.5% of base salary toward the purchase of Enbridge common shares. The executives participate in this plan along with all other employees.

Perquisites
Executives receive an annual perquisite allowance to offset expenses related to their position. This includes the cost of owning and operating a vehicle, parking and recreational clubs. These allowance levels are reviewed regularly for competitiveness. Mr. Jarvis is also reimbursed for a portion of costs for personal financial planning.

	Perquisite allowance (2012)	Financial planning reimbursement
Guy Jarvis	$30,000	50%, up to $5,000
Narin Kishinchandani	$20,000	-
Glenn Beaumont	$20,000	-
Arunas Pleckaitis	$25,000	-
James Grant	$20,000	-

Medical, Dental and Insurance Benefits
Medical, dental and insurance benefits are available to meet the specific needs of individuals and their families. The executives participate in the same plan as all other employees. The plans are structured to provide minimum basic coverage with the option of enhanced coverage at a level that is competitive and affordable.

The Committee reviews the retirement and other benefits regularly. These benefits are a key element of a total compensation package, and are designed to be competitive and reasonably meet the needs of executives in their current roles and when they retire from the Company.

Compensation Changes in 2013
The Committee reviews Enbridge's compensation philosophy and practices every year with assistance from Mercer, to ensure they are appropriate, competitive and continuing to meet their intended goals.

There are no major compensation design or program changes approved by the Committee for implementation in 2013.

As part of its ongoing assessment, Enbridge will continue to review its compensation programs during the course of 2013. Any changes will be brought forward to the Committee and the Enbridge Board for decision. Approved changes would come into effect in 2014.

2012 Performance and Compensation

2012 Performance - Enbridge

Enbridge made tremendous progress on many fronts in 2012, continuing to build a solid and secure foundation for its future growth. Enbridge achieved strong growth in earnings and cash flow in 2012, achieving its guidance range. Adjusted earnings per share (EPS) rose 11% in 2012 to $1.62 per common share, building on an 11% increase in 2011 and a 13% increase in 2010.

Having entered 2012 with $12 billion in commercially secured growth projects in execution, Enbridge steadily added to that portfolio during the year and exited 2012 with a total of $26 billion in commercially secured growth projects over 2012 to 2016. These opportunities alone are expected to drive 10% plus average annual EPS growth through 2016.

In December 2012, Enbridge announced its 2013 guidance for adjusted earnings of $1.74 to $1.90 per share, the mid-point of the guidance range which represents an increase of approximately 12% over 2012. Also in December 2012, the Enbridge Board approved an increase in the quarterly dividend to $1.26 per share, which equates to an annualized increase of 12% for 2013. This increase reflects Management's and the Enbridge Board's confidence in both Enbridge’s near-term and medium-term outlook and its ability to grow earnings and cash flow. Enbridge has increased its dividend by an average of 12% per year over the last ten years, and paid dividends for 60 years.

In 2012, Enbridge committed approximately $600 million to expand Enbridge Gas Distribution’s natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth in the GTA.

Enbridge continued to grow its Green Energy portfolio in 2012 through the acquisition and start-up of the 50-MW Silver State North solar project in Nevada and the acquisition of a 50% interest in the 150-MW Massif de Sud Wind Project in Quebec.

With a growing slate of growth projects, Enbridge continued to demonstrate a strong competency in major project execution in 2012. With more than 20 major projects underway during the course of the year, the vast majority remained on schedule and on, or below, budget. Enbridge was also able to successfully onboard more than 3,000 employees in Canada and the U.S. to effectively support its current and future growth.

In 2012, Enbridge continued to make solid progress in further reinforcing safety and operational integrity across all of Enbridge’s business units. Enbridge is doing this through its comprehensive operational risk management assessment and planning initiative, identifying and implementing further risk mitigation strategies to provide assurance that Enbridge will achieve its safety, integrity and environmental protection objectives. Enbridge’s goal is to achieve top-quartile performance, if not best in class, along several safety and integrity dimensions. Enbridge has also established an Operational Risk Management Plan (ORM), which is a roadmap of programs that are required to sustain an industry-leading position. Enbridge will obtain independent verification of its performance, and the results will be monitored by the Enbridge Board.

For the fifth year in a row, Enbridge was included in the Global 100 Most Sustainable Corporations in the World ranking. Enbridge was also included on the 2012/2013 Dow Jones Sustainability World Index and the Dow Jones Sustainability North America Index and was made a constituent of the 2012/2013 FTSE4Good Index. Enbridge was also included on the 2012 Carbon Disclosure Leadership Index and was named one of Canada’s Greenest Employers and one of Canada’s Top 100 Employers for 2013.

2012 Performance – Enbridge Gas Distribution

During 2012, the Company measured performance in the areas of financial results, safety and reliability, customer satisfaction, and a composite of customer-related indicators. In 2012, the Company continued to grow the business with strong earnings and made significant progress towards achieving its long term goal of being an industry leader in public and employee safety and system integrity in order to deliver natural gas to its customers safely and reliably. This includes areas such as incident responses to emergencies, integrity management and damage avoidance and detection. In terms of the Company's journey towards being a leader in customer satisfaction, while the Company met a variety of stretch targets during the year, there is room for further improvement in other areas such as Customer Commitments Met, First Call Resolution and the Quality of Communication. The overall performance of the Company in 2012 was above target. The business unit component of the short term incentive payout for all of the named executives is aligned to aggregated business unit[1] results. The Company represents approximately 90% of the overall business unit in terms of earnings. The following table summarizes the business unit 2012 performance results:

Business Unit Performance[1]

Performance Area	Weight	Measures	Results (% of target)
Financial	40%	Net Income that is weather normalized to provide a fair assessment of performance. The 2012 results were $177 million compared to a target of $175 million.	**145%**
Safety and Reliability	40%	Measured by the following indices: - Integrity Management, which gauges program effectiveness for correcting records of critical assets, condition monitoring and assurance that high pressure pipelines are operating under the maximum allowable operating pressure; - Worker & Contractor Safety, which measures safety observations, safety training results for both employees and all contractors, quality safety assurance results, as well as injuries and accidents; - Leak Management, which gauges the completion of the Leak Survey program including identification of leaks found and the repair of those leaks within an acceptable time period; - Damage Avoidance, which gauges program effectiveness for all damages and unplanned outages; - Incident Response, which gauges the preparedness of the Incident Response Team to react to emergency incidents quickly and effectively to ensure those incidents are made safe for all stakeholders; - Public Safety Awareness index, which includes safety reputation score, safety drivers overall score, as well as customer equipment compliance and quality assurance faults.	**134%**
Customer	20%	The customer commitment composite measures the quality of handling customer calls and services provided, customer bill accuracy, quality of communication, as well as the results of the customer satisfaction survey.	**83%**

1 "Business unit" includes the Company and the following affiliate operations: Enbridge Gas New Brunswick Inc., Gazifère Inc. and St. Lawrence Gas Company, Inc.

The business unit performance multiplier is 1.28 out of 2.0.

2012 Pay Decisions – Summary

Early in 2012, the Committee determined base salary increases, and medium and long-term incentive awards. Base salary increases of 4.1% to 5.2%, depending on the executive, were implemented on

April 1, 2012 to maintain their competitive position relative to the market. Mr. Jarvis received a salary increase of 13.9% to better align his position relative to the competitive market.

In March 2012, Enbridge granted 215,900 incentive stock options to the named executives of the Company. This grant reflected an award at target for this compensation program and the Black-Scholes value of the stock options at the time of grant. In August 2012, Enbridge granted 169,400 performance stock options to Mr. Jarvis. This grant also reflected target delivery for this compensation program and the Black-Scholes value of the stock options at the time of grant, and includes performance requirements. Effective January 1, 2012, Enbridge granted 13,350 performance stock units to the named executives of the Company which resulted in total direct compensation (base salary + short-term incentive + medium-term incentive + long-term incentives) being appropriately positioned relative to the competitive market.

In early 2013, the Committee approved short-term incentive awards of $783,320 for the named executives including an award of $239,010 to the President of the Company. These awards were determined based on a combination of corporate (Enbridge), business unit and individual performance relative to objectives established at the start of 2012.

See the discussion for each of the named executives starting on page A17.

Base Salary

Base salary levels as of December 31, 2012 are set out in the table below:

	2012 base pay ($)	Increase from 2011 (%)	2011 base pay ($)	Increase from 2010 (%)
Guy Jarvis [1]	400,000	14%	350,000	21%
Narin Kishinchandani	234,000	4%	225,000	13%
Glenn Beaumont	322,920	4%	310,500	4%
Arunas Pleckaitis	302,809	5%	288,390	2%
James Grant	266,596	5%	253,900	15%

1 Mr. Jarvis' salary increase reflects a 4.0% market adjustment on Apr 1, 2012 and a 9.9% increase August 1, 2012 to better align his position relative to the competitive market.

See the discussion for each executive starting on page A17 for information about base salary increases.

Short-Term Incentive

The short-term incentive is awarded based on performance against a combination of Enbridge corporate, business unit and individual objectives.

Corporate Performance

Enbridge's 2012 corporate performance was measured by adjusted EPS. This is a metric that focuses on return to shareholders and is aligned with how investors and security analysts assess Enbridge's performance on an annual basis. Adjusted EPS is closely aligned with Enbridge's targets and objectives and is consistent with information reported regularly to the investor community. It is a metric that is understandable from an employee perspective. The annual Enbridge Board-approved budget establishes the target (1.0 multiplier) for this metric. The minimum (0) and maximum (2.0) multipliers are set using the low end and top end of the external guidance range that is publicly disclosed prior to the beginning of 2012. The Adjusted EPS metric represents 25% of the named executives' short-term incentive award.

Enbridge's 2012 EPS guidance range was $1.58 – $1.74 as approved by the Enbridge Board prior to the beginning of 2012. Actual performance was $1.62.

The Committee also considered Enbridge's performance compared to other companies in its performance stock unit peer group and companies in the TSX and TSX Composite indices, as measured by dividend per share growth, total shareholder return and reward to risk over the past one, three, five and ten year periods. Enbridge's 2012 performance on all of the key performance indicators was very strong, featuring:

- 11% EPS growth;
- 15% dividend per share growth (one of the highest in its peer group);
- A reward to risk ratio at the 93rd percentile of the industry; and
- Competitive total shareholder return in all periods (one year: 89th percentile; three year: 98th percentile; five year: 100th percentile; and 10 year: 100th percentile).

Use of Discretion

During 2012, Enbridge undertook, with the Enbridge Board approval, a supplementary financing plan that included $2.8 billion of common equity, preferred equity and debt pre-funding actions that were not provided for in the original budget, prompted by the significant expansions to Enbridge's five-year growth capital plan, which emerged over the course of the year.

Although these actions had an adverse impact on 2012 Enbridge EPS, they were necessary and prudent steps to support the medium and long-term objectives of Enbridge.

The Committee approved an adjustment to the calculated Enbridge EPS result utilized for the corporate performance multiplier for short-term incentive purposes only, to better align the short-incentive awards for employees with the positive near-term and long-term outcomes for Enbridge shareholders and Enbridge. Adjusting out the impact of the specific pre-funding actions noted above, resulted in an adjusted EPS of $1.676 (versus $1.62 per share) and a short-term corporate multiplier of 1.20 out of 2.0. This adjustment is reflected in the detailing of each named executive's compensation, beginning on page A17.

Business Unit Performance

Business unit performance is measured by a variety of metrics tailored to reflect the success in executing the business unit operations, strategies and initiatives for which the executives are accountable. See page A12 for an outline of the business unit performance results.

The overall business unit multiplier for the Company was 1.28 out of 2.0.

Individual Performance

Individual performance is measured by objectives established at the start of the year by each executive. The President's objectives are established in consultation with the President & Chief Executive Officer of Enbridge, taking into account the Company's financial, operational and strategic priorities. The President establishes individual objectives for the other executives, also at the beginning of the year, basing them on areas of strategic and operational emphasis related to their portfolio, the development of succession candidates, employee engagement, community involvement and leadership.

Overall Performance

The table below shows how each executive's overall performance multiplier was calculated in 2012:

	A – Enbridge Corporate performance			B - Business unit performance			C - Individual performance			Overall performance multiplier [1]
	Weight ×	Corporate multiplier =	Total A	Weight ×	Business unit multiplier =	Total B	Weight ×	Individual multiplier =	Total C	Total A+B+C
Guy Jarvis	25%	1.20	0.30	50%	1.28	0.64	25%	1.65	0.41	1.35
Narin Kishinchandani	25%	1.20	0.30	50%	1.28	0.64	25%	1.60	0.40	1.34
Glenn Beaumont	25%	1.20	0.30	50%	1.28	0.64	25%	1.50	0.38	1.32
Arunas Pleckaitis	25%	1.20	0.30	50%	1.28	0.64	25%	1.60	0.40	1.34
James Grant	25%	1.20	0.30	50%	1.28	0.64	25%	1.50	0.38	1.32

1 Differences in the calculated amounts and the overall performance multipliers are due to rounding.

The overall performance multiplier is used to calculate each named executive's short-term incentive as follows:

	Base salary ($) ×	Target ×	Overall performance multiplier =	Calculated short-term incentive award	Actual short-term incentive award ($) [1]
Guy Jarvis [2]	400,000	50%	1.35	270,500	239,010
Narin Kishinchandani	234,000	35%	1.34	109,746	109,750
Glenn Beaumont	322,920	40%	1.32	169,856	169,860
Arunas Pleckaitis	302,809	35%	1.34	142,017	142,010
James Grant	266,596	35%	1.32	122,701	122,690

[1] The calculated short-term incentive awards vary from the amount obtained by applying the formula because of rounding.

[2] Mr. Jarvis' calculated result differs from mathematical result due to proration of change to short-term incentive targets throughout the year. Please see page A5 for more information.

Medium and Long-Term Incentives

Awards in 2012

Performance Stock Units

The table below shows the performance stock units granted to the named executives in early 2012:

	A Performance stock units granted (#)	B Value ($) (A x $36.38) [1]	C Value (%) (B / salary on Dec. 31, 2011)
Guy Jarvis	5,700	207,366	59%
Narin Kishinchandani	1,900	69,122	31%
Glenn Beaumont	2,350	85,493	28%
Arunas Pleckaitis	1,800	65,484	23%
James Grant	1,600	58,208	23%

[1] For more information on the value of the 2012 Performance Stock Unit grant see Note 1 under the heading "Summary Compensation Table" on page A22 of this Schedule.

Incentive Stock Options

The table below shows the incentive stock options granted to the named executives in early 2012:

	A Stock options granted (#)	B Value ($) (A x $5.00) [1]	C Value (%) (B / salary on Dec. 31, 2011)
Guy Jarvis	91,600	458,000	131%
Narin Kishinchandani	31,100	155,500	69%
Glenn Beaumont	38,200	191,000	62%
Arunas Pleckaitis	29,250	146,250	51%
James Grant	25,750	128,750	51%

[1] For more information on the value of the 2012 Stock Option grant see Note 2 under the heading "Summary Compensation Table" on page A22 of this Schedule.

Forecast Payouts

The performance stock units granted in 2010 vested on December 31, 2012. The forecast performance multiplier is 2.0 based on the following:

	Target	Result	Forecast Performance multiplier
EPS	$1.40	$1.62 (Actual)	2 X (50% weighting)
P/E ratio	75th percentile	100^{th} percentile (Forecast)	2 X (50% weighting)

The table below shows the forecast performance stock unit payouts to the named executives in early 2013[1]:

	Performance stock units granted in 2010 [2]	+	Equivalent to reinvested dividends	=	Total performance stock units	x	Forecast performance multiplier [3]	x	Final share price ($)	=	Payout ($) [4]
Guy Jarvis	7,800		758.69		8,558.69		2.00		41.61		712,255
Glenn Beaumont	2,600		252.90		2,852.90		2.00		41.61		237,418
Arunas Pleckaitis	3,000		291.81		3,291.81		2.00		41.61		273,944
James Grant	2,000		194.54		2,194.54		2.00		41.61		182,629

1 Mr. Kishinchandani was not a member of the Company's executive team at the time of grant in 2010 and did not receive performance stock units. He was granted restricted stock units that matured in 2012. See the table below for amounts paid out.
2 The number of units have been adjusted to reflect the Enbridge stock split of May 2011.
3 The final performance multiplier will be determined in late February 2013 with payout due within 2.5 months of year end.
4 Differences in the calculated amounts and the forecast payout values are due to rounding.

The table below shows the restricted stock unit payouts to Mr. Kishinchandani on December 31, 2012:

	Restricted stock units granted in 2010 [1]	+	Equivalent to reinvested dividends	=	Total restricted stock units	x	Final share price ($)	=	Payout ($)
Narin Kishinchandani	1,000		89.53		1,089.53		39.32		42,840

1 The number of units have been adjusted to reflect the Enbridge stock split of May 2011.

Named Executive Profiles

The profiles for each of the named executives provide the following information:
- A summary of the total direct compensation over the past three year period;
- A summary of the individual accomplishments in 2012; and
- The award decisions by the Committee and the President.

Guy Jarvis
President

Total Direct Compensation

	2012		2011	2010
	$	%	$	$
Cash				
Base salary	375,500	19.1	315,287	284,172
Short-term incentive	239,010	(9.4)	263,910	230,520
	$614,510	**6.1**	**$579,197**	**$514,692**
Equity				
Performance stock units	207,366	(38.1)	335,040	368,394
Incentive stock options	458,000	13.1	404,800	538,118
Performance stock options [1]	719,950	100.0	-	-
	$1,385,316	**87.2**	**$739,840**	**$906,512**

Information on the values presented in this table is provided in the notes to the “Summary Compensation Table” found on page A22 of this Schedule.
[1] This value represents the expected value granted in 2012, valued using the full-term and representing a 5-year period (2012 – 2016).

Base Salary
Mr. Jarvis received a 4.0% salary increase on April 1, 2012 to reflect an annual market adjustment and an additional 9.9% salary increase effective August 1, 2012, to better align his position relative to the competitive market.

Short-Term Incentive
25% of Mr. Jarvis' short-term incentive is based on Enbridge corporate performance measured in 2012 by adjusted EPS. The performance multiplier on this measure was determined to be 1.20 out of 2.0. See page A13 for more information.

The business unit performance accounts for 50% of Mr. Jarvis' short-term incentive award. The overall business unit multiplier is 1.28 out of 2.0. See page A14 for more information.

The remaining 25% of Mr. Jarvis' short-term incentive award is based on an individual performance. See page A14 for more information.

In 2012, Mr. Jarvis:
- completed all deliverables within the Company's operational risk management plan that resulted in demonstrable reduction in the Company's risk profile;
- with the exception of capital structure, negotiated settlement of all other matters in the Company's 2013 cost of service re-basing regulatory application;
- delivered strong earnings performance for the Company;
- secured Board of Director approvals and made application to the regulator for the Greater Toronto Area project; and
- developed a strategic execution plan to position the Company for success during its next incentive regulation period.

Mr. Jarvis' individual performance multiplier was 1.65 out of 2.0.

Mr. Jarvis' combined 2012 short-term incentive award, based on the performance described above, was $239,010.

Medium and Long-Term Incentives
Mr. Jarvis was awarded 91,600 incentive stock options and 5,700 performance stock units in March 2012, and 169,400 performance stock options in August 2012.

Narin Kishinchandani
Vice President, Finance

Total Direct Compensation

	2012		2011	2010
	$	%	$	$
Cash				
Base salary	231,750	8.4	213,750	173,289
Short-term incentive	109,750	(11.6)	124,100	100,800
	$341,500	**1.1**	**$337,850**	**$274,089**
Equity				
Performance stock units	69,122	54.7	44,672	-
Restricted stock units	42,840	(8.8)	46,999	23,615
Incentive stock options	155,500	44.0	108,000	54,929
	$267,462	**34.0**	**$199,671**	**$78,544**

Information on the values presented in this table is provided in the notes to the "Summary Compensation Table" found on page A22 of this Schedule.

Base Salary
On April 1, 2012, Mr. Kishinchandani received a salary increase of 4.1% to maintain market competitiveness.

Short-Term Incentive
25% of Mr. Kishinchandani's short-term incentive award is based on Enbridge corporate performance measured in 2012 by adjusted EPS. The performance multiplier for this measure was determined to be 1.20 out of 2.0. See page A13 for more information.

The business unit performance accounts for 50% of Mr. Kishinchandani's short-term incentive award. The overall business unit multiplier is 1.28 out of 2.0. See page A14 for more information.

The remaining 25% of Mr. Kishinchandani's short-term incentive award is based on individual performance. See page A14 for more information.

In 2012, Mr. Kishinchandani:
- achieved successful conversion to US GAAP for financial reporting and obtained approval of the Ontario Energy Board for transition of regulatory accounting for rate-making to US GAAP, starting 2013;
- achieved a higher degree of integration with the business as part of the journey to transform the Finance Department into an effective business support organization; and
- initiated improvements to the performance management processes to enable improved alignment with strategy going forward.

Mr. Kishinchandani's individual performance multiplier was 1.60 out of 2.0.

Mr. Kishinchandani's combined 2012 short-term incentive award, based on the performance described above, was $109,750.

Medium and Long-Term Incentives

Mr. Kishinchandani was awarded 31,100 incentive stock options and 1,900 performance stock units in March 2012.

Glenn Beaumont

Senior Vice President, Operations

Total Direct Compensation

	2012		2011	2010
	$	%	$	$
Cash				
Base salary	319,815	3.9	307,875	262,826
Short-term incentive	169,860	(10.9)	190,590	175,500
	$489,675	**(1.8)**	**$498,465**	**$438,326**
Equity				
Performance stock units	85,493	2.1	83,760	61,399
Incentive stock options	191,000	(3.3)	197,600	88,445
	$276,493	**(1.7)**	**$281,360**	**$149,844**

Information on the values presented in this table is provided in the notes to the "Summary Compensation Table" found on page A22 of this Schedule.

Base Salary

On April 1, 2012, Mr. Beaumont received a salary increase of 4.2% to maintain market competitiveness.

Short-Term Incentive

25% of Mr. Beaumont's short-term incentive award is based on Enbridge corporate performance measured in 2012 by adjusted EPS. The performance multiplier for this measure was determined to be 1.20 out of 2.0. See page A13 for more information.

The business unit performance accounts for 50% of Mr. Beaumont's short-term incentive award. The overall business unit multiplier is 1.28 out of 2.0. See page A14 for more information.

The remaining 25% of Mr. Beaumont's short-term incentive award is based on individual performance. See page A14 for more information.

In 2012, Mr. Beaumont:

- delivered strong earnings performance in the Company and its affiliates;
- led a restructuring of Enbridge Gas New Brunswick in response to, and minimizing, the negative impact of government-imposed changes to the Gas Distribution Act in New Brunswick;
- delivered improved operational safety performance including shortened times for emergency response and leak repairs;
- introduced a comprehensive operational governance review process and introduced the Central Safety and Local Safety Committee structure to continue to drive the safety culture of the organization;
- introduced a Contract Centre of Excellence, further strengthening the oversight of all operational contracts in all performance dimensions; and
- led formulation of the Company's initiatives to position it to be "Simply the Best" utility in North America along the dimensions of safety, employee engagement, productivity, financial performance and customer experience.

Mr. Beaumont's individual performance multiplier was 1.50 out of 2.0.

Mr. Beaumont's combined 2012 short-term incentive award, based on the performance described above, was $169,860.

Medium and Long-Term Incentives

Mr. Beaumont was awarded 38,200 incentive stock options and 2,350 performance stock units in March 2012.

Arunas Pleckaitis

Vice President, Regulatory, Public & Government Affairs

Total Direct Compensation

	2012		2011	2010
	$	%	$	$
Cash				
Base salary	300,406	4.8	286,632	279,645
Short-term incentive	142,010	(10.7)	159,060	156,240
	$442,416	**(0.7)**	**$445,692**	**$435,885**
Equity				
Performance stock units	65,484	17.3	55,840	70,845
Incentive stock options	146,250	5.7	138,400	99,617
	$211,734	**9.0**	**$194,240**	**$170,462**

Information on the values presented in this table is provided in the notes to the “Summary Compensation Table” found on page A22 of this Schedule.

Base Salary

Mr. Pleckaitis received a salary increase of 5.2% on April 1, 2012 to maintain market competitiveness.

Short-Term Incentive

25% of Mr. Pleckaitis’ short-term incentive award is based on Enbridge corporate performance measured in 2012 by adjusted EPS. The performance multiplier for this measure was determined to be 1.20 out of 2.0. See page A13 for more information.

The business unit performance accounts for 50% of Mr. Pleckaitis’ short-term incentive award. The overall business unit multiplier is 1.28 out of 2.0. See page A14 for more information.

The remaining 25% of Mr. Pleckaitis’ short-term incentive award is based on individual performance. See page A14 for more information.

In 2012, Mr. Pleckaitis:

- directed efforts related to the Company’s 2013 Rebasing Application with the Ontario Energy Board which resulted in a successful negotiated settlement on all but one issue;
- advanced the development of the Company’s strategy related to its “Next Generation Incentive Plan” which will be filed with the Ontario Energy Board in 2014;
- directed the development and successful launch of the Company’s “Natural Gas Advocacy Plan”; and
- directed the Company’s government relations strategy which resulted in the successful passing of “Bill 8 One Call” legislation in the province of Ontario.

Mr. Pleckaitis’ individual multiplier was 1.60 out of 2.0.

Mr. Pleckaitis’ combined 2012 short-term incentive award, based on the performance described above, was $142,010.

Medium and Long-Term Incentives

Mr. Pleckaitis was awarded 29,250 incentive stock options and 1,800 performance stock units in March 2012.

James Grant

Vice President, Business Development & Customer Strategy

Total Direct Compensation

	2012		2011	2010
	$	%	$	$
Cash				
Base salary	264,480	13.5	233,095	210,983
Short-term incentive	122,690	(13.9)	142,490	123,700
	$387,170	**3.1**	**$375,585**	**$334,683**
Equity				
Performance stock units	58,208	15.8	50,256	47,230
Incentive stock options	128,750	7.3	120,000	72,618
	$186,958	**9.8**	**$170,256**	**$119,848**

Information on the values presented in this table is provided in the notes to the "Summary Compensation Table" found on page A22 of this Schedule.

Base Salary

Mr. Grant received a salary increase of 5% on April 1, 2012 to maintain market competitiveness.

Short-Term Incentive

25% of Mr. Grant's short-term incentive award is based on Enbridge corporate performance measured in 2012 by adjusted EPS. The performance multiplier for this measure was determined to be 1.20 out of 2.0. See page A13 for more information.

The business unit performance accounts for 50% of Mr. Grant's short-term incentive award. The overall business unit multiplier is 1.28 out of 2.0. See page A14 for more information.

The remaining 25% of Mr. Grant's short-term incentive award is based on individual performance. See page A14 for more information.

In 2012, Mr. Grant:

- enhanced the Company's focus on Customer Commitment metrics and overall Customer Satisfaction. Progress was made in the 2012 year relating to billing accuracy, electronic billing adoption by customers, business partner alignment and a number of call centre operating statistics. These initiatives led to an increase in overall customer satisfaction, as measured by an independent third party survey;
- improved performance in unregulated storage operations;
- streamlined the business development effort so that it is geared to commercially viable technologies and applications for natural gas; and
- consolidated the Marketing and Sales functions within the Company and implemented a focus on two primary areas: Customer Growth and Demand Side Management programs for customers.

Mr. Grant's individual performance multiplier was 1.50 out of 2.0.

Mr. Grant's combined 2012 short-term incentive award, based on the performance described above, was $122,690.

Medium and Long-Term Incentives

Mr. Grant was awarded 25,750 incentive stock options and 1,600 performance stock units in March 2012.

2012 RESULTS

Summary Compensation Table

The table below shows the total paid and granted to the named executives of the Company for the years ended December 31, 2012, 2011 and 2010.

Executive and principal position	Year	Salary ($)	Share-based awards ($) [1]	Option-based awards ($) [2]	Non-equity (annual incentive plan) ($) [3]	Pension value ($) [4]	All other compensation ($) [5,6,7]	Total compensation ($)
Guy Jarvis	2012	375,500	207,366	1,177,950	239,010	305,000	31,818	2,336,644
President	2011	315,287	335,040	404,800	263,910	287,000	63,083	1,669,120
	2010	284,172	368,394	538,118	230,520	4,000	35,120	1,460,324
Narin Kishinchandani	2012	231,750	111,962	155,500	109,750	79,000	21,949	709,911
Vice President, Finance	2011	213,750	91,671	108,000	124,100	83,000	46,384	666,905
	2010	173,289	23,615	54,929	100,800	89,000	12,911	454,544
Glenn Beaumont	2012	319,815	85,493	191,000	169,860	130,000	26,037	922,205
Senior Vice President, Operations	2011	307,875	83,760	197,600	190,590	99,000	55,759	934,584
	2010	262,826	61,399	88,445	175,500	150,000	23,468	761,638
Arunas Pleckaitis	2012	300,406	65,484	146,250	142,010	138,000	25,350	817,500
Vice President, Regulatory, Public	2011	286,632	55,840	138,400	159,060	71,000	58,643	769,575
& Government Affairs	2010	279,645	70,845	99,617	156,240	52,000	25,000	683,347
James Grant	2012	264,480	58,208	128,750	122,690	121,000	21,788	716,916
Vice President, Business	2011	233,095	50,256	120,000	142,490	187,000	48,311	781,152
Development & Customer Strategy	2010	210,983	47,230	72,618	123,700	77,000	23,966	555,497

1 Amounts in this column reflect the number of performance stock units awarded multiplied by the unit value which is determined by the volume weighted average of an Enbridge common share on the TSX for 20 trading days prior to the grant date. The unit value for the performance units awarded was $36.38 (2012), $27.92 (2011) and $23.62 (2010), adjusted where appropriate to reflect the Enbridge stock split of May 2011. The unit value considers the notional dividends that are reinvested during the performance period. The unit value of the performance units varies from the accounting value which is based on a mark-to-market valuation of an Enbridge common share at the end of each financial quarter, including notional dividends accrued. Particulars on performance stock units are set forth on page A7 of this Schedule.

2 Stock Option Plans:
Amounts in this column reflect the number of options awarded multiplied by the option value. The option value for all regular stock option grants is determined using the Black-Scholes method. For compensation reporting, we use only the accounting option value:

Assumptions	March 2012	February 2011	November 2010		February 2010		2009
	Grant date accounting value	Grant date accounting value	Grant date fair value	Accounting value	Grant date fair value	Accounting value	Grant date fair value and accounting value
Expected option term in years	6	6	6	6	6	6	6
Expected volatility	19.00%	17.80%	19.50%	19.10%	26.60%	19.10%	26.80%
Expected dividend yield	2.95%	3.41%	3.11%	3.11%	3.64%	3.64%	3.88%
Risk free interest rate	1.45%	2.88%	2.40%	2.40%	2.65%	2.65%	2.22%
Exercise price	$38.34	$28.78	$27.84	$27.84	$23.30	$23.30	$19.81
Regular option value	$5.00	$4.00	$3.96	$3.87	$4.66	$3.28	$3.37

Particulars on stock options are set forth beginning on page A9 of this Schedule.

We use the Black Scholes method to determine the performance stock option value and discount it, using a Monte Carlo simulation to reflect the Enbridge common share price targets that must be met for the performance stock options to vest. We granted all performance stock options in CA$. The below values have been adjusted.

Assumptions	**2012 Grant date fair value and accounting value**
Expected option term in years	8
Expected volatility	16.10%
Expected dividend yield	2.80%
Risk free interest rate	1.60%
Exercise price	$39.34
Performance discount	$0.11
Performance option value	4.25

Particulars of this longer-term incentive vehicle are set forth beginning on page A8 of this Schedule.

[3] Amounts in this column reflect the short-term incentive plan awards earned in 2012 and payable on February 28, 2013. Awards are based on Enbridge performance and business unit and individual performance. Particulars on the short-term incentive awards calculations for each named executive are set forth on page A15 of this Schedule. There are no long-term non-equity incentive plans within the Enbridge compensation programs.

[4] The pension value is equal to the compensatory change shown in the defined benefit plans table.

[5] Amounts in this column include the flexible perquisite allowance, excess flexible benefit credits paid to the executive, the taxable benefit from loans by the Company (which were made prior to the enactment of the Sarbanes-Oxley Act), parking, relocation subsidies, financial counseling benefits and other incidental compensation.

[6] In 2012, the executives were given a flexible perquisites allowance in the amount of $20,000 for Mr. Jarvis, $25,000 for Mr. Pleckaitis and $20,000 for each of Messrs. Beaumont, Grant, and Kishinchandani.

[7] The Company has a flexible benefit program where employees receive flex credits which they can use to purchase various health and insurance benefits, apply as contributions to the savings plan, or be paid as additional compensation. Flexible benefit credits directed to the savings plan or paid as additional compensation to the executives are reported in All Other Compensation.

Incentive Plan Awards

Outstanding option-based and share-based awards as of December 31, 2012:

Option Based Awards						Share-Based Awards			
Executive	Number of securities underlying unexercised options [1]	Option exercise price [1]	Option expiration date	Value of unexercised in-the-money options ($) [1, 2]		Number of units that have not vested	Unit maturity date	Market or payout value of units not vested [3]	Market or payout value of vested Share-based Awards not paid out or distributed [4]
	(#)	($)		Vested	Unvested	(#)		($)	($)
Guy Jarvis	91,600	$38.34	2-Mar-22	-	428,688	5,865	31-Dec-14	157,696	712,255
	75,900	$28.78	14-Feb-21	-	1,081,196	7,002	31-Dec-13	188,277	
	169,400	$39.34	15-Aug-20	-	623,392				
	28,900	$23.30	16-Feb-20	-	570,053				
	22,000	$19.81	25-Feb-19	-	510,730				
Narin Kishinchandani	31,100	$38.34	2-Mar-22	-	145,548	1,955	31-Dec-14	52,565	-
	27,000	$28.78	14-Feb-21	96,154	288,461	1,698	31-Dec-13	45,643	
	11,800	$23.30	16-Feb-20	116,378	116,378				
	16,800	$19.81	25-Feb-19	292,509	97,503				
	12,800	$20.21	19-Feb-18	291,968	-				
	10,200	$19.13	9-Feb-17	243,678	-				
	3,200	$18.24	13-Feb-16	79,312	-				
	3,200	$15.84	3-Feb-15	86,976	-				
Glenn Beaumont	38,200	$38.34	2-Mar-22	-	178,776	2,418	31-Dec-14	65,015	237,418
	49,400	$28.78	14-Feb-21	175,926	527,777	3,183	31-Dec-13	85,580	
	19,000	$23.30	16-Feb-20	187,388	187,388				
	27,800	$19.81	25-Feb-19	484,033	161,344				
	27,800	$20.21	19-Feb-18	634,118	-				
	15,600	$19.13	9-Feb-17	372,684	-				
	18,600	$18.24	13-Feb-16	461,001	-				
	18,400	$15.84	3-Feb-15	500,112	-				
	6,000	$12.86	4-Feb-14	180,960	-				
Arunas Pleckaitis	29,250	$38.34	2-Mar-22	-	136,890	1,852	31-Dec-14	49,799	273,944
	34,600	$28.78	14-Feb-21	123,219	369,658	2,122	31-Dec-13	57,054	
	21,400	$23.30	16-Feb-20	211,058	211,058				
	29,800	$19.81	25-Feb-19	518,855	172,952				
	29,800	$20.21	19-Feb-18	679,738	-				
	17,400	$19.13	9-Feb-17	415,686	-				
	19,600	$18.24	13-Feb-16	485,786	-				
	22,400	$15.84	3-Feb-15	608,832	-				
	45,200	$12.86	4-Feb-14	1,363,232	-				
James Grant	25,750	$38.34	2-Mar-22	-	120,510	1,646	31-Dec-14	44,266	182,629
	30,000	$28.78	14-Feb-21	106838	320,513	1,910	31-Dec-13	51,348	
	15,600	$23.30	16-Feb-20	153,855	153,855				
	23,400	$19.81	25-Feb-19	407,423	135,808				
	12,400	$20.21	19-Feb-18	282,844	-				
	11,600	$19.13	9-Feb-17	277,124	-				
	8,800	$18.24	13-Feb-16	218,108	-				
	4,400	$15.84	3-Feb-15	119,592	-				
	4,800	$12.86	4-Feb-14	144,768	-				

1. The value of the unexercised in-the-money stock options is based on the Enbridge closing share price on the TSX on December 31, 2012 of $43.02. Where applicable, the number of options or units and the option exercise prices (as listed on the TSX) have been adjusted consistent with the Enbridge stock split of May 2011.
2. The market value of the performance stock units that have not vested is calculated by the number of units granted plus the number of units credited in lieu of reinvested dividends multiplied by the threshold performance multiplier and the Enbridge closing share price on December 31, 2012 of $43.02.
3. We have assumed a threshold performance multiplier of 0.625, based on meeting minimum EPS threshold (50%) and a relative price to earnings ratio ranking of at least 50th percentile (50%). See page A15 for details.
4. This is a reflection of the estimated payout value of the 2010 Performance Stock Unit grant, which vested on December 31, 2012 but will not be paid out until approximately March 2013. We have assumed a performance multiplier of 2.0.

Value Vested or Earned in 2012

Executive	Option-based awards – value vested during the year ($)	Share-based awards – value vested during the year ($) [1]	Non-equity incentive plan compensation – value earned during the year ($) [2]
Guy Jarvis	1,206,940	712,255	239,010
Narin Kishinchandani	250,339	42,840	109,750
Glenn Beaumont	453,089	237,418	169,860
Arunas Pleckaitis	442,417	273,944	142,010
James Grant	302,153	182,629	122,690

1 The performance stock units granted in 2010 matured on December 31, 2012. See page A15 for details.

2 Based on Enbridge and business unit performance at an "exceeds" rating, and varying individual performance. See executive profiles for more information.

The value of the option-based awards is based on the following:

Grant name	Grant date	Grant price	2012 vesting date	Closing Price on 2012 vesting date
2011 General Grant (CA)	14-Feb-2011	$28.775	14-Feb-2012	$39.10
2010 General Grant (CA)	16-Feb-2010	$23.295	16-Feb-2012	$39.20
2008 General Grant (CA)	19-Feb-2008	$20.21	19-Feb-2012	$37.58
2007 Performance (CA) Addition 1	19-Feb-2008	$20.21	19-Feb-2012	$37.58
2009 General Grant (CA)	25-Feb-2009	$19.805	25-Feb-2012	$38.41
2009 General Grant (CA) Addition 1	25-Feb-2009	$19.71	15-Jun-2012	$39.38
2007 Performance (CA)	15-Aug-2007	$18.285	15-Aug-2012	$39.47
2011 General Grant (CA) Addition 1	02-Sep-2011	$32.02	02-Sep-2012	$38.81
2010 General Grant (CA) Addition 1	12-Nov-2010	$27.84	12-Nov-2012	$39.22

1 Where applicable, the grant prices have been adjusted (as listed on the TSX) consistent with the Enbridge stock split of May 2011.

Enbridge Shares Used for Purposes of Equity Compensation

Enbridge grants options to employees of the Company under Enbridge's current stock options plans, which were approved by Enbridge shareholders in 2007:

- the incentive stock option plan (2007), as amended and restated (2011); and
- the performance stock option plan (2007), as amended and restated (2011) and further amended (2012).

Before these plans were approved, Enbridge issued stock options and performance stocks options under its legacy incentive stock option plan (2002). While Enbridge no longer grants options under this plan, as of December 31, 2012, there were still 4,120,510 options outstanding.

Enbridge common shares reserved for equity compensation as of December 31, 2012

Plan	Number of securities to be issued upon exercise of outstanding options, warrants and rights (#) (a)	Weighted-average exercise price of outstanding options, warrants and rights ($) (b)	Number of securities remaining available for future issue under equity compensation plans (excluding securities reflected in column (a)) (#) (c)
Current stock option plans	29,951,331	27.76	18,529,024
Legacy stock option plan	4,120,510	16.92	-

Plan Restrictions

Shares Enbridge can reserve for issue under all stock option plans	52,000,000 in total, or 6.5% of our total issued and outstanding Enbridge shares as of December 31, 2012 • for an employee – no more than 5% of the total shares issued and outstanding • for an executive or other insider – no more than 10% of the total shares issued and outstanding
Shares that can be issued in a one-year period	• for an insider or his or her associate – no more than 5% of the total shares issued and outstanding • for insiders as a group – no more than 10% of the total shares issued and outstanding
The number of shares that can be issued as incentive stock options (within the meaning of the US Internal Revenue Code) to designated employees of Enbridge's US subsidiaries	Up to 2,000,000 shares can be issued to these employees under each option plan unless, at the time of the grant: • the employee owns shares that give him or her more than 10% of the total combined voting power of all classes of shares in his or her employer, or of its parent or subsidiary, unless the grant price is at least 110% of the fair market value of the shares, and the options are to be exercised within five years of the grant date, *or* • the employee has options that can be exercised in a single calendar year for shares that have a total fair market value of more than US$100,000 (or the amount set out in the US Internal Revenue Code)
Options the President & CEO of Enbridge can grant to new executives when they join the Company	Up to 2% of the total shares outstanding at the time of the grant (undiluted) or the amount stated in the policies of the Committee (whichever is less)

Making changes to the stock option plans

In 2012, the Enbridge Board approved changes to the proration of performance stock options upon retirement to reflect their view that a grant of performance stock options relates to the five calendar year period even though the grant date occurs partway through the calendar year. These changes are permitted by the terms of the plan and do not require shareholder approval. The changes are:

Plan text before amendments	Plan text after amendments
• Enbridge prorates the performance stock options for the period of active employment in the five year period starting on the grant date. • These prorated options can be exercised until the earlier of three years after retirement and the expiry of the term.	• Enbridge prorates the performance stock options for the period of active employment in the five year period starting January 1 of the year of the grant. • These prorated options can be exercised until the later of three years after retirement or 30 days after the date the share price targets must be met(or up to the date the options expire, whichever is earlier).

Termination Provisions of Stock Option Plans

The termination provisions for the Enbridge stock option plans are summarized below. Performance stock options have the same termination provisions as the incentive stock options except for the following differences:

- for retirement, Enbridge prorates performance stock options for the period of active employment in the 5 year period starting January 1 of the year of grant. These options can be exercised until the later of three years after retirement or 30 days after the date by which the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the share price targets are met;
- for death, unvested options are pro-rated and the plan assumes performance requirements have been met;
- for involuntary not for cause termination, unvested options are pro-rated; and
- for change of control, the plan assumes the performance requirements have been met.

Pro-ration is based on active employment during the time vesting period (and any notice period on an involuntary not for cause termination will count as active employment), and pro-rated options are deemed to be time vested.

Reason for termination	Provision
Resignation	Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
Retirement	Incentive stock options continue to vest and options that are vested or become vested can be exercised up to three years from retirement or until the option term expires (whichever is sooner). Conditions for Performance stock options are detailed above.
Death	All options vest and can be exercised up to 12 months from the date of death or until the option term expires (whichever is sooner).
Disability	*Current stock option plans*: Options continue to vest based on the regular provisions of the plan. *Legacy stock option plan*: Options continue to vest. Vested options can be exercised up to three years from the date of disability or until the option term expires (whichever is sooner).
Termination - involuntary, not for cause	*Current stock option plans*: Unvested options continue to vest, and options that are vested or become vested can be exercised up to 30 days after the notice period expires or until the option term expires (whichever is sooner). *Legacy stock option plan*: Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
- involuntary, for cause	*Current stock option plans*: All options are cancelled on the date of termination. *Legacy stock option plan*: Can exercise vested options up to 30 days from the date of termination or until the option term expires (whichever is sooner).
- change of control or reorganization	*Current stock option plans*: For a change of control, options vest on a date determined by the Committee before the change of control. For any other kind of reorganization, options are to be assumed by the successor company. If they are not assumed, they will vest and the value will be paid in cash. *Legacy stock option plan*: Options will be assumed by the successor company. If they are not assumed, they will vest and the value will be paid in cash.

Retirement Benefits

Defined Benefit Plans

The following table outlines estimated annual retirement benefits, accrued pension obligations and compensatory and non-compensatory changes for the executives under the defined benefit pension plans. All information is based on the assumptions and methods used for the purposes of reporting the Company's financial statements, and which are described in the notes to the Company's financial statements.

Executive	No. of years of credited service	Annual benefits payable ($) At year-end	Annual benefits payable ($) At age 65	Accrued obligation at start of the year ($)	Compensatory change ($)[1]	Non-compensatory change ($)[2]	Accrued obligation at year-end ($)
Guy Jarvis[3]	12.5	110,000	282,000	1,503,000	305,000	265,000	2,073,000
Narin Kishinchandani[4]	9.58	41,000	137,000	541,000	79,000	104,000	724,000
Glenn Beaumont	26.5	137,000	234,000	2,130,000	130,000	231,000	2,491,000
Arunas Pleckaitis[5]	25.75	189,000	211,000	2,683,000	138,000	188,000	3,009,000
James Grant	29.58	122,000	186,000	2,046,000	121,000	176,000	2,343,000

1 The compensatory change includes current service cost, special arrangements and the difference between actual and estimated earnings.

2 The non-compensatory change includes interest on the accrued obligation at the start of the year, changes in actuarial assumptions and other experience gains and losses.

3 Mr. Jarvis has 1.33 years of credited service with the Company. A portion of Mr. Jarvis' retirement benefit will be paid from other Enbridge entities based on his service with those entities.

4 Mr. Kishinchandani joined the senior management pension plan on December 1, 2006.

5 The final average earnings calculation for Mr. Pleckaitis will include bonuses for all service.

Termination of Employment and Change of Control Arrangements

The Company has entered into employment agreements with Messrs. Jarvis and Pleckaitis, but not with its other executives. Upon resignation, retirement or termination without cause or constructive dismissal, each of the executives would be entitled to receive pension benefits under the senior management pension plan. The severance amounts payable to the executives upon termination without cause or constructive dismissal, except for Messrs. Jarvis and Pleckaitis, would be individually determined based upon service, age, salary level and title. In the cases of Messrs. Jarvis and Pleckaitis, they would be entitled to the amounts described under "Executive Employment Agreement" below for termination without cause or constructive dismissal.

The following table discloses the lump sum value of pension benefits accrued under the defined benefit pension plans for the executives in the event that they resigned, retired, or were terminated involuntarily without cause or constructively dismissed as of December 31, 2012:

Executive	Pension ($)
Guy Jarvis	1,630,000
Narin Kishinchandani	575,000
Glenn Beaumont	2,342,000
Arunas Pleckaitis	4,120,000
James Grant	3,035,000

Further information about the pension plan is set forth under the heading "Retirement Plan Benefits" of this Schedule.

Executive Employment Agreement

The Company has entered into executive employment agreements with Messrs. Jarvis and Pleckaitis which provide that should they experience involuntary termination (other than for cause) or constructive dismissal (as defined in the agreement) they will be paid the amounts described in the agreement.

In the event of an involuntary termination, other than for cause, or a voluntary termination within 60 days following constructive dismissal, as at December 31, 2012, Messrs. Jarvis and Pleckaitis would be entitled to the following estimated incremental benefits:

	Base salary ($)[1]	Short-term incentive ($) [2]	Longer-term incentive ($) [3]	Benefits ($) [4]	Pension ($) [5]	Total payout ($)
Guy Jarvis	800,000	494,430	3,733,018	125,475	573,000	5,725,923
Arunas Pleckaitis	605,618	123,000	1,104,262	37,568	486,000	2,356,448

1 Amount in this column equals two times the annual salary.

2 Amount in this column equals two times an annual short-term incentive award. The amount was calculated based on the short-term incentive awards paid in 2010 and 2011.

3 Amount equals the in-the-money value of un-exercisable stock options as at December 31, 2012 and the performance stock units outstanding at December 31, 2012 assuming they mature and the Enbridge earnings per share multiplier was 1.5 and the price to earnings ratio multiplier was 1.5. For the purposes of these calculations, the closing price of an Enbridge share on December 31, 2012 was $43.02.

4 Amount in this column equals two times Flex Credits (benefit allowance). The amount for Mr. Jarvis also includes two times the annual perquisite and $20,000 for financial and career counseling.

5 This includes the value of two additional years of credited service and age at the assumed date of termination of December 31, 2012.

Change of Control

On a change of control of Enbridge, entitlement to short-term incentive, vesting of stock options, and maturing of performance units is accelerated as set forth below:

Plan	Result
Short-Term Incentive	Pro-rated short-term incentive payment based on service prior to the change of control assuming Corporate Performance at target, business unit performance as determined by Enbridge's President & Chief Executive Officer and individual performance meets requirements.
Stock Options	Unvested stock options conditionally vest not more than 30 days and not less than five days prior to the change of control.
Performance Units	All outstanding units mature 30 days prior to the change of control based on applicable performance measures achieved.

The following outlines the estimated incremental payment of longer-term incentive value in the event of a change of control on December 31, 2012:

Executive	Incremental Longer-Term Incentive Value ($) [1]
Guy Jarvis	4,044,395
Narin Kishinchandani	381,248
Glenn Beaumont	540,206
Arunas Pleckaitis	1,147,003
James Grant	349,984

1 Amount equals the in-the-money value of un-exercisable stock options as at December 31, 2012 and the value of the performance stock units outstanding at December 31, 2012. For the purpose of this calculation, a multiplier of 1.5 was applied. The closing price of an Enbridge share on December 31, 2012 was $43.02.

Directors' Compensation

Directors' Compensation Table

The following table sets forth the compensation elements and total compensation earned by each of the Company's directors in consideration for their service on the Company's Board of Directors during the financial year ended December 31, 2012.

Director[1]	Fees Earned[2] ($)	All Other Compensation[3] ($)	Total ($)
J. R. Bird	23,000	1,000	24,000
J. L. Braithwaite	23,000	2,000	25,000
P. D. Daniel [4]	11,250	-	11,250
D. A. Leslie	26,000	2,000	28,000
A. Monaco [5]	3,750	-	3,750
D.T. Robottom	15,000	-	15,000

1 Mr. Jarvis did not receive any compensation for acting as a director of the Company. He is compensated solely for holding the office of President.

2 Fees earned include annual retainers and meeting fees and is discussed in greater detail below. Directors' fees payable to employees of Enbridge who are directors of the Company are paid directly to Enbridge.

3 All other compensation includes an amount for meetings attended outside the director's Province of residence and is discussed below.

4 Mr. Daniel resigned as a director on September 30, 2012.

5 Mr. Monaco was appointed as a director on October 16, 2012.

Directors' Compensation Plan

Directors of Enbridge Gas Distribution other than the President are compensated in accordance with a Directors' Compensation policy which became effective in 1997 and was revised in 1998. Enbridge Gas Distribution's Board of Directors is responsible for the development and implementation of the Directors' Compensation policy.

With the exception of the director who serves as the Company's President, each director receives $15,000 per annum for his or her services as a director as well as $3,000 per annum for serving as a member of any committee of the Board of Directors and an attendance fee of $1,000 for each board and committee meeting. Directors are also entitled to receive reimbursement for their out-of-pocket travel expenses incurred in connection with board and committee meetings. Directors are also entitled to $500 for meetings attended where the meeting is held outside of the Province or State of residence of such director. In addition, the Chair of the Audit, Finance & Risk Committee receives $3,000 per annum for serving as Chair of such committee. The President of the Company does not receive any additional compensation for acting as a director of the Company.

Unlike compensation for the executives, the Directors' Compensation policy is not designed to pay for performance. Rather, directors receive retainers for their services in order to help ensure unbiased decision-making.

BOMA INTERROGATORY #1

INTERROGATORY

Issue #1

B, 1, 1, P5 - par. Explanation of Terms

(a) Please explain what the "EGD Ontario corporate trial balance" is. Is that document the same as the publicly filed EGD corporate financial statements, which are included in evidence? If not, where can the document be found in evidence?

(b) Par. 17 - Please provide a description of each "adjustment, regrouping, and elimination required" to derive the Ontario utility rate base, income, and capital structure results, referencing for each step the pertinent regulatory rule(s).

RESPONSE

a) The Ontario corporate trial balance being referred to contains financial data specific to Ontario only and excludes any financial data related to an out of province operation, St. Lawrence Gas Limited. The publicly filed EGD audited financial statements provided at Exhibit D, Tab 1, Schedule 1, consolidate the financial data for Ontario and St. Lawrence Gas. For purposes of generating the Ontario Utility financial results, the calculations begin with the Ontario only financial data and are then adjusted as described within the exhibits provided in evidence. Exhibit B, Tab 1, Schedule 4, provides a reconciliation of what items are included in consolidated audited income statement results versus Ontario Utility only income statement results.

b) Within the referenced paragraph 17, the Company provided some examples of some of the required treatments necessary to convert corporate financial statement results and data into Ontario Utility only cost of service results. Details of specific adjustments are available in each of the Utility financial exhibits provided, as an example in Exhibit B, Tab 4, Schedule 1, all of the necessary adjustments are described on pages 2, 5 and 6. The Company declines to provide a library of the history of the regulatory calculations and rules for determining cost of service utility financial results (such as the average of average rate base calculation or capital structure balanced to utility rate base concept) as the regulatory mechanisms are generally accepted practice that have been in place for a number of years.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #2

INTERROGATORY

Issue #1

Ref: B.1.4, P3

(a) Please provide a breakdown of the individual amounts for each of the regrouped items. Show where the amounts are being regrouped to, and how that impacts utility numbers. For example, in (d), line 2, "Amounts related to St. Lawrence Gas, unregulated storage, oil and gas" provide the individual amounts that make up the $22.8 million.

(b) Please explain each item, and if regrouped, how that is done.

(c) Please explain fully what is meant by the income taxes on a utility "stand-alone" basis.

RESPONSE

a) For Exhibit B, Tab 1, Schedule 4, page 3, the following table provides a breakdown of individual amounts within those lines which contain more than one item.

Exhibit B, Tab 1, Schedule 4, pg. 3	St. Lawrence Gas ($Millions)	Unregulated Storage ($Millions)	Oil & Gas ($Millions)	Total ($Millions)
Consolidated other revenue	0.6	20.3	1.9	22.8
Consolidated operation and maintenance	8.8	1.8	1.1	11.7
Consolidated depreciation	1.4	2.6	0.2	4.2

b) The evidence provided in pages 2 through 4 of Exhibit B, Tab 1, Schedule 4 indicates what each item is within the reconciliation of audited total corporate financial results to Utility regulated financial results. The reconciliation adjustments and regroupings to achieve Utility regulated results are not actual entries that are

Witnesses: K. Culbert
R. Small

performed within the financials of EGD but rather are indications of different treatments of all of the noted items in achieving Utility regulated results.

c) The term income taxes on a utility stand-alone basis is meant to indicate that the income tax amounts contained within the regulated Utility results do not include any non-utility or unregulated activity amounts of revenue or expense or related tax treatments as permitted by the Canada Revenue Agency for such activities.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #3

INTERROGATORY

Issue #1

Deferral and Variance Accounts

In C1, T1, Schedules 1 through 6 - Enbridge has provided brief explanatory notes on the Earnings Sharing Account, the Gas Distribution Access Rate Cost Deferral Account, and the Tax Rate and Rule Change Deferral Account and a lengthy discussion of the Transactional Services Deferral Account. Could Enbridge provide comparable brief background notes on each of the remaining Non-Commodity and Commodity Deferral Accounts, including, for each account:

- Reference to the decision that authorized the account, and the pertinent excerpt from that decision.
- A copy of the approved wording of the account.
- How long the account has been in existence.
- A description of the rationale for the account.
- A description of the operation of the account.
- Any other pertinent aspects of the account.

RESPONSE

Within the 2012 rate setting proceeding, EB-2011-0277, the Board approved a settlement agreement where parties, including BOMA, agreed to the establishment of all of the deferral and variance accounts listed at Exhibit C1, Tab 1, Schedule 1, page 2.

Further, the scope for each of the accounts is found within Appendix C in the Board Rate Order for EB-2011-0277. How long each of the accounts has been in existence is not pertinent to the requested clearance of amounts within the approved accounts for 2012 and EGD declines the opportunity to spend time compiling such data.

Witnesses: K. Culbert
D. Small
R. Small

BOMA INTERROGATORY #4

INTERROGATORY

Issue #1

C, T1, Sch 2, pp 1-8, Preamble

BOMA is having difficulty following the determination of the amount of the GDARCDA. Can Enbridge provide a description of the expenditures that comprise the amount ($1,097.8 M) that it wishes to clear, including why the expenditures are required, and whether they were capital and operating. From tables 4 to 8 of C, T1, Sch 2, Enbridge suggests the impacts on the revenue requirement include an increase to rate base, decrease in gas sales, and increase to O&M. Please explain how and why these changes arise. First, what are the monies actually spent on, and second, how do they get incorporated into the revenue requirement calculation in Tables 4 through 8?

RESPONSE

The majority of the costs required and included within the finalizing of the 2012 GDARCDA amounts arose and are the result of the Board's Notice of Amendment to a Rule (Gas Distribution Access Rule), resulting from the Board-initiated Customer Service Standards for Natural Gas Distributors ("new Customer Service Rules") Proceeding EB-2010-0280. In addition, there are incremental staffing resource costs not included in 2007 base rates required to support the 2007 OEB approved GDAR system improvements to enable standardized electronic data exchanges between gas vendors and Ontario gas distributors.

In the Board's NOTICE OF AMENDMENT TO A RULE, EB-2010-0280, dated October 14, 2011; section IV the Board acknowledged the cost impacts:

> While the Board acknowledges that the Proposed Amendments will cause additional costs for the Gas Distributors, the Board believes that the benefits of the Proposed Amendments outweigh their costs.

In accordance with the Company's filings, the following are the impacts to the Company, of implementing new Customer Service Rules and to support the 2007 OEB approved GDAR system improvements.

Witnesses: K. Culbert
A. Dhoot
K. Lakatos-Hayward
R. Small

1. Capital cost $406 K:

   Costs were incurred to make updates to EGD's Customer Information System (CIS) to implement the new Customer Service Rules in the following areas:

   a) Rules for determining when a bill is overdue for payment;
   b) When correcting billing errors, informing customers that they can request a refund when money is owed to them and sending letters to customers when a meter error has been detected;
   c) Updating disconnection notices to provide adequate notice and inform of the options available to avoid disconnection;
   d) Updating process of calling customers prior to disconnection to advise of payment arrangements available;
   e) Reviewing Security Deposits 12 months after being fully paid and calculating arrears net of any security deposit already paid;
   f) Revised arrears management by sending cancellation notice letters to customers who miss making a payment arrangement payment; and
   g) Revised management of Landlord Agreements to provide clear accountability for gas charges at rental properties at various points in time.

2. O&M costs $200K:

   External service provider costs were incurred to implement new Customer Service Rules. More specifically, these are costs incurred to handle customer inquiries regarding accelerated security deposit refunds and approvals, costs of training service provider staff on the amended process for managing landlord/tenant agreements and costs of updating customer communications. In addition, there were incremental staffing resource costs not included in 2007 base rates required to support the OEB approved GDAR system improvements to enable standardized electronic data exchanges between gas vendors and Ontario gas distributors.

3. LPP revenue loss $916:

   In order to be compliant with the new Customer Service Rules, in 2012 the Company adopted the "minimum payment period" requirement of the new Customer Service Rules and allowed 3 additional days before late payment penalty ("LPP") was calculated for residential customers, as referenced in

EB-2010-0280, "Customer Service Amendments to the Gas Distribution Access Rule, Submission of Enbridge Gas Distribution Inc., filed February 17, 2011, Appendix A; section 1.

The Company has utilized reporting from the CIS to calculate LPP revenue foregone, attributable to the utility's adoption of this practice.

The dollar amount of payments received up to 3 days after the LPP effective date (which appears on the bill but is not used to assess LPP) is multiplied by the OEB prescribed monthly interest payment of 1.5% to calculate the LPP revenue foregone. Please refer to the table below.

Table 1: Calculated LPP Revenue Foregone	
Payments Received up to 3 days after LPP Effective Date	$61.0 million
LPP %	1.50%
LPP Revenue Foregone	$ 0.9 million

Witnesses: K. Culbert
A. Dhoot
K. Lakatos-Hayward
R. Small

BOMA INTERROGATORY #5

INTERROGATORY

Issue #1

C, T1, Sch 4, p1

Has Bill 114 been enacted into legislation? When?

RESPONSE

Such information is accessible to the public within the Legislative Assembly of Ontario website, where it can be seen that Bill 114 received Royal Assent in June of 2012, over one year ago.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #6

INTERROGATORY

Issue #2

C, T1, Sch 6 (general)

(a) Please confirm that Enbridge is, in effect, seeking a rehearing and/or review of the Board's decision in EB-2012-0055 that revenues earned through capacity release activities should be treated as gas cost reductions ("0055", p14) and that, accordingly, Enbridge would not receive a share of the net revenues received from capacity release activities in 2011.

(b) Apart from the fact the present case deals with the TSDA from 2012, rather than 2011, please confirm there are no material changed circumstances in the nature of the capacity release activities in 2012 from those in 2011, which would underpin the request for a different characterization of the revenues from those activities.

RESPONSE

EGD is not seeking a rehearing and/or a review of the Boards's decision in EB-2012-055 regarding the treatment of revenues associated with capacity release exchange activities in 2011. The findings of the Board required Enbridge to "stream" additional 2011 capacity release revenues to ratepayers. The Board also directed Enbridge to propose a methodology for disposing of the incremental amount to ratepayers. The Company complied with both of those directives.

The Board also directed Enbridge to discuss how it proposes to dispose of 2012 capacity release net revenues in the Draft Rate Order filing. Enbridge's proposal was to lead evidence in its 2012 ESM proceeding to support its position that 2012 net revenues from capacity release transactions are appropriately recorded in the 2012 TSDA. The Board did not deny our proposal.

EGD has filed evidence as part of the 2012 ESM application that it believes will give the Board a more complete understanding of the circumstances and nature of capacity release transactions.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOMA INTERROGATORY #7

INTERROGATORY

Issue #2

Ibid. P11

(a) Please provide a table equivalent to Table 2 for Enbridge's Central Delivery Area.

(b) Please explain whether the "Direct Purchase Deliveries", as referenced on page 2, line 4, are all consumers taking delivery of gas at Empress/AECO and redelivering that gas to either the CDA or EDA. In other words, are these all Western Bundled-T services?

(c) Please relate the answer in (a) to Table 1 on p5, and Table 2 on p11, in which Direct Purchase (Ontario T-service) is shown as 349,653 (CDA) and 32,693 (EDA), respectively. Are these the same DP transactions that are referred to on p2?

(c) What is meant by Direct Purchase (Ontario T-Service) on the two tables? Are these customers (or marketers) that hold their own transportation service on TCPL or some other pipeline, or is the term being used more generally to describe the volume of gas that is purchased by customers from suppliers other than Enbridge? If the latter, what volumes are represented by customers with their own upstream transportation services, and what volumes are customers that take a Bundled-T service from Enbridge?

RESPONSE

a) Please see Table 1 attached.

b) c) and d) The amount identified as Direct Purchase on the applicable Table(s) represents the daily volume forecasted to be received in the applicable franchise area from those customers operating under an Ontario T-Service Direct Purchase Agreement (“DPA”). As per that DPA these customers are obligated to deliver a fixed volume every day. These customers either through an Agent, Broker or Marketer have made their own arrangements for the associated gas supply and transportation to get the gas to the franchise area.

Witnesses: J. Denomy
J. LeBlanc
D. Small

Table 1 - Control Delivery Area Demand Summary

Centralized Delivery Area (CDA) As per 2012 Budget		January to March	April to October
		Avg Winter Demand	Avg Summer Demand
GJ's	Peak Day		
Demand	3,164,452	1,732,505	563,679
Less Curtailment	(129,737)	-	-
	3,034,716	1,732,505	563,679
TCPL FT Capacity	90,424	90,424	90,424
TCPL STFT	250,000	250,000	-
Ontario T-Service	349,653	349,653	349,653
Sub Total	690,077	690,077	440,077
TCPL Short Haul	139,879		-
TCPL STS	369,464		-
Delivered Service	1,741,278		-
Peaking Service	94,018	-	-
	3,034,716	690,077	440,077
Amount Required from Short Haul and or STS		1,042,428	123,602

BOMA INTERROGATORY #8

INTERROGATORY

Issue #2

Ibid, p2

Preamble - In the stylized picture on p2, Enbridge shows the Base Load supply well in excess of Base Load Demand. It appears to be used to meet about two-thirds of average day demand as well. What percentage of base load supply volumes are transported through TCPL and Alliance/Vector, respectively?

(a) Why is base load supply not contracted in an amount just equal to base load (summer) demand? What percentage of average day demand in 2012 was covered by base load supply in each of the last five years?

(b) How does Enbridge decide what percentage of average day demand (see diagram) should be covered by base load supply? Please provide a detailed answer, with calculations, if possible.

(c) The diagram shows the "Dawn discretionary" service being used to provide the remaining one-third (approximately) of average day demand, plus a portion (of about thirty percent) of average winter day demand. How much of average winter day demand was covered by Dawn discretionary service in 2012, and in each of the last five years? What does the term "Dawn discretionary" supply mean? Why are the terms "Dawn" and "discretionary" linked together? Is discretionary being juxtaposed against "firm supply"? Must all "discretionary" supply be taken at Dawn?

(d) Please explain what "discretionary supply" means in the above context. Does it refer to the commodity, transportation, or both? If the commodity, what does it mean?

(e) What is included in "Dawn discretionary" supplies? Please provide a breakdown, according to various sources of gas/transportation mode.

- Volumes delivered on the Alliance/Vector pipeline system for WCSB, on capacity held by Enbridge.

Witnesses: J. Denomy
J. LeBlanc
D. Small

- Volumes delivered by Vector on capacity held by Enbridge, but purchased in the US.

- Volumes delivered at Dawn by third parties, which held capacity on Alliance/Vector or Vector, and purchased by Enbridge at Dawn. Please provide a percentage breakdown of each form of arrangement.

(f) What are "winter supplies" (aside from storage withdrawals) which are shown as providing that part of average winter demand not supplied by Dawn discretionary demand, and part of the demand on colder than average winter days. What percentage of winter supplies, in total, and for each of the last five years, are supplied from storage, and from gas delivered directly to the customers?

(g) Pursuant to what transportation arrangements are winter supplies provided to the EDA; the CDA, in total? Please show the paths used to provide the winter supply in each case.

(h) Please show the paths and the contractual arrangements by which base load, Dawn discretionary, and winter supply, are transported to and from storage, and show what percentage of winter average, and peak demand are supplied from storage.

RESPONSE

The diagram shown at Figure 1 of Exhibit C, Tab 1, Schedule 6, page 2 was intended to provide a visual depiction that would show the services that EGD relies upon to meet its peak day requirements including Base Load Supply, Dawn Supplies, Storage and Peaking Services. It was also intended to demonstrate that during the summer when demand is at its lowest, excess base load supply will be injected into storage. It was not intended to provide an exact one-to-one breakdown of the various supplies and demand.

For example, Base Load on the Demand side of the equation excludes heat load almost entirely as it is based on summer months usage, whereas, Base Load on the Supply Side represents usage at a 100% load factor for all direct purchase and system supply customers. Using the term Base Load does not imply an equivalence on the Demand and Supply side.

Witnesses: J. Denomy
J. LeBlanc
D. Small

Enbridge develops its supply portfolio based upon how it intends to meet peak day and manages those contracts with the help of storage to load balance between supply and demand while ensuring safe and reliable service to its customers while optimizing the supply portfolio using existing contractual parameters.

In response to parts a) through h), EGD will attach an overview of how it develops its gas supply portfolio and a forecast of EGD's 2012 portfolio which is attached as Appendix A.

Witnesses: J. Denomy
J. LeBlanc
D. Small

GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation of Enbridge Gas Distribution Inc. (the "Company" or "Enbridge") during the 2012 Test Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements the Company develops a gas supply plan using a model known as "SENDOUT". This model determines the optimum monthly supply portfolio using existing contractual parameters, i.e., transportation contracts including storage deliverability and also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

2. Enbridge expects to acquire its system gas supply under the following types of contracts during the Test Year:

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited ("TransCanada") or via Alliance Pipeline to the Company's franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.
- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company's contracted capacity on the Vector Pipeline.

Witness: D. Small

- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn. However, the Company may consider alternative sources such as western Canadian supply utilizing TCPL STFT capacity either for economic or operational reasons.

Enbridge currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. The Company expects to continue this practice for its 2012 gas supply arrangements.

3. The following is Enbridge's forecast of gas supply acquisition during the test year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	3 439.8	124.4
Ontario Production	0.7	0.0
Peaking	37.3	1.3
Chicago Supply	1837.1	64.9
Delivered Supply	1488.8	52.6
	6803.7	240.2

Commodity Costs

4. The price assumptions reflect the market's assessment (as at the time of preparation of this evidence) of the different expected delivery points for the Company's forecast of gas supply.

5. The market's assessment is determined at any point in time by the use of the simple average of forward quoted prices as reported by various media and other services,

over a period of 21 business days for a basket of pricing points, and pricing indices that reflect the Company's gas supply acquisition arrangements.

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from August 3, 2011 to August 31, 2011 for the 12 months commencing January 1, 2012 and applied these monthly prices to the 2012 budgeted annual volume gas purchases.

7. In an effort to remove the impact of commodity costs changes the Company removed the impact of the updated price forecast and the October 1, 2011 QRAM prices in a fashion similar to the 2011 Budget that was filed in EB-2010-0146, Enbridge's 2010 rate adjustment application.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2012 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2012 PGVA. While the Company does not anticipate acquiring gas in 2012 via means other than the traditional transportation paths (i.e., TCPL, Alliance/Vector) the possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, Renewable Natural Gas).

Peak Day Coverage

9. Enbridge continues to plan for its peak day coverage based on the 20% probability, multi-peak day design conditions introduced in the EBRO 490 proceeding. These conditions assume 39.5 degree days (Celsius) for the coldest peak. It is assumed these conditions are experienced, on average, about once every five years.

Enbridge is forecasting a design peak day level of 99 280 10^3m^3 (3.5 Bcf) during the winter season of the test year.

Transportation

10. Enbridge has a number of Firm Transportation (“FT”) and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the test year. These include service entitlements with TransCanada, Alliance Pipeline and Vector Pipeline. For purposes of this forecast contracts were priced based upon current tolls and contracts that have an expiry date during the Test Year were deemed to be renewed with the following exceptions. The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

11. During 2011 the Company administered a TCPL FT Turnback process with its Direct Purchase customers in accordance with the System Reliability proceeding mentioned above. The Company received a limited number of requests but they were rejected because they did not meet the criteria established in the System Reliability proceeding. Therefore, there was no change to the Company’s contracted TCPL FT capacity for November 1, 2011 stemming from FT Turnback. During the System Reliability proceeding Enbridge expressed some concerns about

the reliability of its current Peaking Supply contracts. Enbridge had observed that largely the same suppliers were providing Peaking Supply, Direct Purchase supply, and Curtailment Delivered Supply ("CDS"). During January 2011 and February 2011when curtailment was called by Enbridge those concerns became a reality. Certain Direct Purchase customers had their MDV deliveries cut by their suppliers as well as cuts with respect to CDS nominations. In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months. The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

12. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 GJ/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2011 Union tolls.

Storage

13. The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

14. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 GJ broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding dated November 7, 2006 the Board ruled that these contracts should be priced at cost of service rates and that a phased in approach to market based storage was in the best interests of customers in Ontario. Effective April 1, 2010 all of the Company's contracted third party storage is at market based rates.

15. During 2011 the Company issued an RFP for three market based storage contracts that expire March 31, 2012. The cost consequences of these and the other third party storage contracts have been included in the forecast for 2012 gas costs.

<u>Energy Content</u>

16. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.

<u>Schedules</u>

17. The Gas Cost schedules at Exhibit B, Tab 4, Schedule 2, provide the following: Pages 1 and 2 provide the summary of the forecasted gas cost to operations for 2012 based upon an updated supply and transportation portfolio to meet the forecasted volumetric requirement for 2012. Page 3 provides a breakdown of the forecasted 2012 storage and transportation costs that are shown at Item #13, Column 2 of page 2. Page 4 provides a breakdown of the monthly gas in storage balances for rate base purposes in 2012. Pages 5 through 8 are the comparable schedules for 2011 assuming the October 1, 2011 QRAM Reference Price.

BOMA INTERROGATORY #9

INTERROGATORY

Issue #2

Ibid, P5, Table 1

(a) Please confirm that "TCPL FT" capacity is Empress to CDA and Empress to EDA, respectively. If not, explain what are the paths in which this gas flows.

(b) Please confirm that the "TCPL-STFT" is also on Empress - EDA or Empress to CDA. If the STFT capacity, or part of it, is on other "TCPL" paths, such as Great Lakes (Empress to Dawn), please indicate, with percentage breakdown of contracted capacity. Please provide the periods over which the STFT volumes are taken, i.e. the term of each STFT contracts, with the corresponding contract demand and daily volumes.

(c) TCPL Short Haul - Please provide details on which pipeline segments this capacity is held, and give a percentage volume breakdown, for each segment, for example, Dawn/Parkway, Parkway/EDA. Is all the TCPL short-haul firm service? If not, please specify.

(d) Please explain how the STS service is used to supply the CDA and EDA on colder winter days and the peak day, on what paths does the gas travel, using which pipeline capacities held by either TCPL or Enbridge.

(e) Storage and Delivered Services

(i) Please provide a breakdown as between storage, and Delivered Services, in total, for each of the CDA and EDA. What does "Storage" mean in the table, given that a separate item TCPL STS is also shown? Is "withdrawals from storage" what is meant? Is there not duplication?

(ii) Delivered Services are shown in the CDA but not the EDA, on peak day. Please explain fully.

(iii) What are Delivered Services in this context? Please discuss fully, including providing the various receipt points at which "delivered services" are acquired by Enbridge and the volume at each point. For example, how much of the service is gas that Enbridge purchases from third parties

Witnesses: J. Denomy
J. LeBlanc
D. Small

at the CDA, which has been delivered to the CDA by third parties? What is percentage of Delivered Services for which Enbridge holds transportation, and what percentage is moved or delivered by transportation rights held by the vendors?

(iv) What are the paths over which these "delivered services" travel? Please provide percentages including:

Alberta to Dawn via Alliance/Vector; Vector only

Niagara to CDA

Empress to CDA

Other

(v) What percentage of delivered services supplies gas which has been transported via the Alliance pipeline?

(vi) How does Enbridge determine (calculate) the amount of discretionary services that is appropriate to acquire as part of its gas supply plan? Please provide a complete response.

RESPONSE

a) Confirmed.

b) Yes. Please see the attachment to EB-2011-0354 Exhibit I, Issue D2, Schedule 8.5 for a breakdown of STFT for the period November 2011 to March 2012.

c) and d) A listing of the 2012 TCPL Short Haul and STS contracts volumetric amounts and path can be found at Exhibit C, Tab 1, Schedule 6 Appendix C.

e) The line identified as storage and delivered service represents the amount of gas to be either withdrawn from storage or purchased at Dawn and then transported via EGD's contract with Union for M12 capacity from Dawn to Parkway and as such would only be available to meet peak day demand in the CDA. EGD is not privy to how the counterparties that it purchases gas from at Dawn get their supplies to Dawn and any supplies purchased directly in the CDA are considered peaking

Witnesses: J. Denomy
J. LeBlanc
D. Small

services. The level of Discretionary Services in the forecasted supply plan is determined by the amount required in the winter to supplement other supplies to assist in meeting demand and in the summer by the amount required to fill storage.

Witnesses: J. Denomy
J. LeBlanc
D. Small

FRPO INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Please provide the detailed analysis that supports the increase in STFT.

a. Please provide the specific level of demand that would be necessitated by the results of the Design Criteria Study.

b. Please provide the specific calculations and supporting assumptions that determined the "$66.2 or $74.5 million in total of unutilized transportation cost impacts."

c. Using April 2011 to March 2012 actual values, please provide monthly values for:

    i. The quantity of daily firm transport contracted in each TCPL delivery zone.
    ii. The quantity of daily firm transport delivered to other EGD delivery zones by other providers.
    iii. The quantity of daily firm TCPL contracts optimized to generate revenue versus recovered in EGD transportation rates?
    iv. The amount of FT-RAM credits accrued.
    v. The amount of revenue generated by utilization of those credits.
    vi. The demand charges for the transportation that was optimized.

d. Please clarify where the demand charge costs were charged and to what account were the revenues accrued.

Witnesses: J. Sarnovsky
D. Small

RESPONSE

a) The 2013 gas cost was prepared assuming, among other things, a peak day demand based upon the existing Design Day Demand Criteria of 39.5 degree days which equates to a peak day demand of 99 280 10^3m^3 (3.5 Bcf). If the Board were to accept the Company's proposal for a new Design Day Demand Criteria of 43.7 degree days this would equate to a peak day demand of 108 590 10^3m^3 (3.8 Bcf). See the response to Board Staff Interrogatory #13 at Exhibit I, Issue D3, Schedule 1.13.

b) The updated evidence identifies $2.8 million as the amount of the unutilized capacity cost (Exhibit D1, Tab 2, Schedule 1, page 9, para. 2) which is calculated by applying the TCPL-FT toll times the unutilized capacity of 1,350,000 Gj's. If the Board were to accept the Company's proposed changes to the Design Day Demand Criteria then the Company would be required to contract for additional transportation to meet the increase in Peak Day Demand. As discussed in its Gas Cost evidence not all of that incremental capacity would be utilized. That incremental unutilized capacity would increase by 31,375,000 Gj's or $66.2 million.

c) The Company will re-iterate how capacity assignments and FT RAM credits contribute to Transactional Services revenue. While transactional service deals pertaining to transportation optimization utilize the utility transportation contracts, no deal will be entered into at the expense or risk of the customers of the utility. For example, during periods of reduced demand, typically during the summer months, Enbridge may optimize underutilized transportation capacity by executing basic exchanges between two points for a fee charged to a third party (i.e., Enbridge could move gas received at Dawn and redeliver to the CDA). During these same periods of reduced demand the Company may, temporarily release parts of its long haul TCPL capacity to third parties. Tied to each release is an exchange through which Enbridge generally delivers gas at Empress and receives an equivalent volume of gas at Dawn. The credit received from TCPL through the temporary assignment offset by the cost payable to the third party for the transportation capacity represents Transportation Optimization for Transactional Services purposes.

As for FT RAM these credits are only accumulated if a shipper does not utilize 100% of its RAM eligible capacity (i.e., FT or STS). In the case of Enbridge this is generated only when the Company does not fully utilize its STS capacity. For example, if in the month of December Enbridge did not fully utilize its STS capacity then we would have available credits that can be applied against the costs associated with any IT transportation costs that might be incurred by the Company in

the month of December. However if Enbridge does not contract for any IT transportation service in that month then any STS-RAM credits go unutilized as credits cannot be carried forward to a subsequent month. To the extent that the Company required IT transportation for the purposes of meeting the needs of the Utility then any STS-RAM credits received by the Company would go toward lowering the transportation costs to the benefit of the rate payer and be captured as part of the PGVA. If however, the Utility did not require any IT transportation and there was an opportunity to enter into a Transactional Services deal with a third party through the use of IT transportation then any STS-RAM credits received would offset that IT transportation cost and provide a benefit as part of the Transactional Services Transportation Optimization.

The attached table provides the daily contracted demand level of the contracts in place for the months April 2011 to March 2012. Item # 1 represents the contracted TCPL FT capacity from Empress to the CDA. Item # 2 represents the amount of CDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 3 represents the contracted TCPL FT capacity from Empress to the EDA and Item # 4 represents the amount of EDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 5 represents the amount of Empress to EDA capacity that has been released to a third-party (for purposes of this schedule only those capacity assignments that were for an entire month, were included). This is a Transactional Services arrangement that is referred to as an Empress to Dawn Exchange. Enbridge will purchase gas at Empress and as part of the exchange with the counterparty will return the gas to Enbridge at Dawn on the same day. As part of this exchange deal the Company will assign to the counterparty long-haul TCPL capacity. Enbridge will receive a credit from TCPL for the amount of the assignment which is greater than the amount being paid to the counterparty to move the gas to Dawn. For gas costs purposes the assignment is deemed to not have happened i.e., the demand charge cost and commodity cost are included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid for transport to the counterparty is recorded as Transactional Services revenue and recorded as Transportation Optimization. Item # 6 represents the one year assignment of Empress to Iroquois capacity that was mentioned as part of the Gas Supply evidence. Item #'s 7 and 8 represent the Contracted STFT amounts. Item # 9 is the level of Enbridges' contracted TCPL Dawn to CDA capacity and Item # 10 represents the amount of that capacity that has been assigned to ABM's as a part of the System Reliability proceeding. Item # 11 is the level of Enbridges' contracted TCPL Dawn to EDA capacity. Item # 12 represents the amount of the Dawn to EDA capacity that was assigned to third parties (for purposes

of this schedule only those capacity assignments that were for an entire month were included) as part of a Transactional Services deal. Similar to Item # 5 for purposes of gas costs the assignment is deemed to not have happened i.e., the demand charge cost is included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid to the counterparty is recorded as Transactional Services revenue Transportation Optimization. Item #'s 13 to 16 are the remaining transportation arrangements Enbridge has with TCPL. Item #'s 17 and 18 represent the transportation commitments the Company has with Union Gas. Item #'s 19 to 21 represent the revenue and costs associated with the release of capacity to third parties as discussed above. Item #'s 22 to 24 provide the monthly TCPL IT transportation costs and STS RAM credits incurred by the Company. These costs are further broken down between costs incurred for Utility purposes or for purposes of generating Transactional Services revenue – Item #'s 25 & 26. Item # 27 provides the Transactional Services revenue attributable to that transaction and Item # 28 provides the net revenue.

d) See response to part c)

Witnesses: J. Sarnovsky
D. Small

Item #	Transportation	Route	Contracted Daily Volume											
			Column 1 Apr-11	Column 2 May-11	Column 3 Jun-11	Column 4 Jul-11	Column 5 Aug-11	Column 6 Sep-11	Column 7 Oct-11	Column 8 Nov-11	Column 9 Dec-11	Column 10 Jan-12	Column 11 Feb-12	Column 12 Mar-12
	GJ's													
1	TCPL FT - CDA	Empress to CDA	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA	(7,732)	(7,772)	(7,772)	(7,784)	(7,757)	(7,762)	(7,733)	(7,388)	(7,387)	(7,317)	(7,371)	(7,387)
3	TCPL FT - EDA	Empress to EDA	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970
4	Direct Purchase Assignment	Empress to EDA	(15,391)	(15,299)	(15,189)	(14,952)	(14,790)	(14,530)	(14,336)	(14,621)	(12,880)	(13,065)	(12,420)	(11,439)
5	Transactional Services Capacity Release	Empress to EDA	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois	-	-	-	-	-	-	-	26,956	26,956	26,956	26,956	26,956
7	TCPL STFT - CDA	Empress to CDA	-	-	-	-	-	-	-	50,000	175,000	250,000	250,000	125,000
8	TCPL STFT - EDA	Empress to EDA	-	-	-	-	-	-	-	-	50,000	75,000	75,000	25,000
9	TCPL FT Dawn to CDA		149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
10	Direct Purchase Assignment as per System Reliability		(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)
11	TCPL FT Dawn to EDA		114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
12	Tranasactional Services Assignment		(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	-	-	-	-	-
13	TCPL FT Dawn to Iroquois		40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
14	TCPL FT-SN Parkway to CDA		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
15	TCPL STS Parkway to CDA		284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
16	TCPL STS Parkway to EDA		80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
17	Union Gas Dawn to Parkway		2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
18	Union Gas Dawn to Kirkwall		67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000's)													
19	Transactional Services Revenue - credit received from TCPL		2,899.6	2,905.7	2,899.6	2,905.7	2,906.3	2,900.2	2,906.3	-	-	-	-	-
20	Transactional Services Expense - amount paid to counterparty		(2,413.7)	(2,494.2)	(2,413.7)	(2,494.2)	(2,494.2)	(2,413.7)	(2,494.2)	-	-	-	-	-
21	Transactional Services Net Revenue		485.8	411.5	485.8	411.5	412.1	486.4	412.1	-	-	-	-	-
22	TCPL IT costs - Before STS RAM Credits		338.7	172.7	91.5	177.6	236.5	148.3	55.8	647.3	651.4	402.4	586.7	424.0
23	TCPL STS RAM Credits		(316.5)	-	-	-	-	-	-	(608.8)	(612.8)	(375.9)	(540.7)	(398.9)
24	Net Cost		22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
25	Amount charged to Gas Cost		0.2	172.7	91.5	177.6	236.5	148.3	55.8	-	5.1	2.3	-	4.6
26	Amount charged as Transactional Services Expense		22.0	-	-	-	-	-	-	38.5	33.5	24.3	46.0	20.6
			22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
27	Associated Transactional Services Revenue		106.7	-	-	-	-	-	-	367.8	265.0	294.3	332.2	269.6
28	Transactional Services Net Revenue		84.7	-	-	-	-	-	-	329.3	231.5	270.0	286.2	249.1

BOMA INTERROGATORY #10

INTERROGATORY

Issue #2

Ibid, P4

Enbridge stated that:

> "it is important to note that base load transportation exceeds base load demand (also known as average summer daily demand) and the combination of all transportation components exceeds the average winter day demand. It is therefore expected at a general level that there will be surplus transportation capacity that can be made available for optimization on certain days throughout the year. This is considered in the annual ratemaking process. For 2012 an amount of $8 million was incorporated into rates to reflect the ratepayer's share of the generation of transactional services revenue in some form".

Please explain how Enbridge determined that for 2012 an amount of $8 million was appropriately reflected in rates, in respect of anticipated transactional services revenue. Please provide the calculations and assumptions that Enbridge used to arrive at the $8 million number.

RESPONSE

The $8 million amount has been reflected in rates throughout the 2008 to 2012 IR term and was agreed to for 2012 as part of the 2012 ADR Settlement in EB-2011-0277.

Witnesses: J. LeBlanc
D. Small

BOMA INTERROGATORY #11

INTERROGATORY

Issue #2

Ibid, App C

Please provide a more completely annotated version of Appendix C, which explains the significance of each of lines 1 through 29, and which elaborates on the very brief descriptions in column 1.

RESPONSE

Appendix C was intended to provide an update to a schedule that was filed as part of an interrogatory response in Enbridge's 2013 rate proceeding EB-2011-0354 which showed the same information for the April 2011 to March 2012 period. For a complete description of the various line items refer to the response to FRPO Interrogatory #5 at Exhibit I, Issue D2, Schedule 8.5, page 3 of 4 in EB-2011-0354 which is attached as Appendix A.

Witnesses: J. LeBlanc
D. Small

FRPO INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Please provide the detailed analysis that supports the increase in STFT.

a. Please provide the specific level of demand that would be necessitated by the results of the Design Criteria Study.

b. Please provide the specific calculations and supporting assumptions that determined the "$66.2 or $74.5 million in total of unutilized transportation cost impacts."

c. Using April 2011 to March 2012 actual values, please provide monthly values for:

    i. The quantity of daily firm transport contracted in each TCPL delivery zone.
    ii. The quantity of daily firm transport delivered to other EGD delivery zones by other providers.
    iii. The quantity of daily firm TCPL contracts optimized to generate revenue versus recovered in EGD transportation rates?
    iv. The amount of FT-RAM credits accrued.
    v. The amount of revenue generated by utilization of those credits.
    vi. The demand charges for the transportation that was optimized.

d. Please clarify where the demand charge costs were charged and to what account were the revenues accrued.

Witnesses: J. Sarnovsky
D. Small

RESPONSE

a) The 2013 gas cost was prepared assuming, among other things, a peak day demand based upon the existing Design Day Demand Criteria of 39.5 degree days which equates to a peak day demand of 99 280 10^3m^3 (3.5 Bcf). If the Board were to accept the Company's proposal for a new Design Day Demand Criteria of 43.7 degree days this would equate to a peak day demand of 108 590 10^3m^3 (3.8 Bcf). See the response to Board Staff Interrogatory #13 at Exhibit I, Issue D3, Schedule 1.13.

b) The updated evidence identifies $2.8 million as the amount of the unutilized capacity cost (Exhibit D1, Tab 2, Schedule 1, page 9, para. 2) which is calculated by applying the TCPL-FT toll times the unutilized capacity of 1,350,000 Gj's. If the Board were to accept the Company's proposed changes to the Design Day Demand Criteria then the Company would be required to contract for additional transportation to meet the increase in Peak Day Demand. As discussed in its Gas Cost evidence not all of that incremental capacity would be utilized. That incremental unutilized capacity would increase by 31,375,000 Gj's or $66.2 million.

c) The Company will re-iterate how capacity assignments and FT RAM credits contribute to Transactional Services revenue. While transactional service deals pertaining to transportation optimization utilize the utility transportation contracts, no deal will be entered into at the expense or risk of the customers of the utility. For example, during periods of reduced demand, typically during the summer months, Enbridge may optimize underutilized transportation capacity by executing basic exchanges between two points for a fee charged to a third party (i.e., Enbridge could move gas received at Dawn and redeliver to the CDA). During these same periods of reduced demand the Company may, temporarily release parts of its long haul TCPL capacity to third parties. Tied to each release is an exchange through which Enbridge generally delivers gas at Empress and receives an equivalent volume of gas at Dawn. The credit received from TCPL through the temporary assignment offset by the cost payable to the third party for the transportation capacity represents Transportation Optimization for Transactional Services purposes.

As for FT RAM these credits are only accumulated if a shipper does not utilize 100% of its RAM eligible capacity (i.e., FT or STS). In the case of Enbridge this is generated only when the Company does not fully utilize its STS capacity. For example, if in the month of December Enbridge did not fully utilize its STS capacity then we would have available credits that can be applied against the costs associated with any IT transportation costs that might be incurred by the Company in

the month of December. However if Enbridge does not contract for any IT transportation service in that month then any STS-RAM credits go unutilized as credits cannot be carried forward to a subsequent month. To the extent that the Company required IT transportation for the purposes of meeting the needs of the Utility then any STS-RAM credits received by the Company would go toward lowering the transportation costs to the benefit of the rate payer and be captured as part of the PGVA. If however, the Utility did not require any IT transportation and there was an opportunity to enter into a Transactional Services deal with a third party through the use of IT transportation then any STS-RAM credits received would offset that IT transportation cost and provide a benefit as part of the Transactional Services Transportation Optimization.

The attached table provides the daily contracted demand level of the contracts in place for the months April 2011 to March 2012. Item # 1 represents the contracted TCPL FT capacity from Empress to the CDA. Item # 2 represents the amount of CDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 3 represents the contracted TCPL FT capacity from Empress to the EDA and Item # 4 represents the amount of EDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 5 represents the amount of Empress to EDA capacity that has been released to a third-party (for purposes of this schedule only those capacity assignments that were for an entire month, were included). This is a Transactional Services arrangement that is referred to as an Empress to Dawn Exchange. Enbridge will purchase gas at Empress and as part of the exchange with the counterparty will return the gas to Enbridge at Dawn on the same day. As part of this exchange deal the Company will assign to the counterparty long-haul TCPL capacity. Enbridge will receive a credit from TCPL for the amount of the assignment which is greater than the amount being paid to the counterparty to move the gas to Dawn. For gas costs purposes the assignment is deemed to not have happened i.e., the demand charge cost and commodity cost are included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid for transport to the counterparty is recorded as Transactional Services revenue and recorded as Transportation Optimization. Item # 6 represents the one year assignment of Empress to Iroquois capacity that was mentioned as part of the Gas Supply evidence. Item #'s 7 and 8 represent the Contracted STFT amounts. Item # 9 is the level of Enbridges' contracted TCPL Dawn to CDA capacity and Item # 10 represents the amount of that capacity that has been assigned to ABM's as a part of the System Reliability proceeding. Item # 11 is the level of Enbridges' contracted TCPL Dawn to EDA capacity. Item # 12 represents the amount of the Dawn to EDA capacity that was assigned to third parties (for purposes

of this schedule only those capacity assignments that were for an entire month were included) as part of a Transactional Services deal. Similar to Item # 5 for purposes of gas costs the assignment is deemed to not have happened i.e., the demand charge cost is included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid to the counterparty is recorded as Transactional Services revenue Transportation Optimization. Item #'s 13 to 16 are the remaining transportation arrangements Enbridge has with TCPL. Item #'s 17 and 18 represent the transportation commitments the Company has with Union Gas. Item #'s 19 to 21 represent the revenue and costs associated with the release of capacity to third parties as discussed above. Item #'s 22 to 24 provide the monthly TCPL IT transportation costs and STS RAM credits incurred by the Company. These costs are further broken down between costs incurred for Utility purposes or for purposes of generating Transactional Services revenue – Item #'s 25 & 26. Item # 27 provides the Transactional Services revenue attributable to that transaction and Item # 28 provides the net revenue.

d) See response to part c)

Witnesses: J. Sarnovsky
D. Small

Item #	Transportation	Route	Contracted Daily Volume Column 1 Apr-11	Column 2 May-11	Column 3 Jun-11	Column 4 Jul-11	Column 5 Aug-11	Column 6 Sep-11	Column 7 Oct-11	Column 8 Nov-11	Column 9 Dec-11	Column 10 Jan-12	Column 11 Feb-12	Column 12 Mar-12
	GJ's													
1	TCPL FT - CDA	Empress to CDA	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA	(7,732)	(7,772)	(7,772)	(7,784)	(7,757)	(7,762)	(7,733)	(7,388)	(7,387)	(7,317)	(7,371)	(7,387)
3	TCPL FT - EDA	Empress to EDA	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970
4	Direct Purchase Assignment	Empress to EDA	(15,391)	(15,299)	(15,189)	(14,952)	(14,790)	(14,530)	(14,336)	(14,621)	(12,880)	(13,065)	(12,420)	(11,439)
5	Transactional Services Capacity Release	Empress to EDA	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois	-	-	-	-	-	-	-	26,956	26,956	26,956	26,956	26,956
7	TCPL STFT - CDA	Empress to CDA	-	-	-	-	-	-	-	50,000	175,000	250,000	250,000	125,000
8	TCPL STFT - EDA	Empress to EDA	-	-	-	-	-	-	-	-	50,000	75,000	75,000	25,000
9	TCPL FT Dawn to CDA		149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
10	Direct Purchase Assignment as per System Reliability		(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)
11	TCPL FT Dawn to EDA		114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
12	Tranasactional Services Assignment		(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	-	-	-	-	-
13	TCPL FT Dawn to Iroquois		40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
14	TCPL FT-SN Parkway to CDA		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
15	TCPL STS Parkway to CDA		284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
16	TCPL STS Parkway to EDA		80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
17	Union Gas Dawn to Parkway		2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
18	Union Gas Dawn to Kirkwall		67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000's)													
19	Transactional Services Revenue - credit received from TCPL		2,899.6	2,905.7	2,899.6	2,905.7	2,906.3	2,900.2	2,906.3	-	-	-	-	-
20	Transactional Services Expense - amount paid to counterparty		(2,413.7)	(2,494.2)	(2,413.7)	(2,494.2)	(2,494.2)	(2,413.7)	(2,494.2)	-	-	-	-	-
21	Transactional Services Net Revenue		485.8	411.5	485.8	411.5	412.1	486.4	412.1	-	-	-	-	-
22	TCPL IT costs - Before STS RAM Credits		338.7	172.7	91.5	177.6	236.5	148.3	55.8	647.3	651.4	402.4	586.7	424.0
23	TCPL STS RAM Credits		(316.5)	-	-	-	-	-	-	(608.8)	(612.8)	(375.9)	(540.7)	(398.9)
24	Net Cost		22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
25	Amount charged to Gas Cost		0.2	172.7	91.5	177.6	236.5	148.3	55.8	-	5.1	2.3	-	4.6
26	Amount charged as Transactional Services Expense		22.0	-	-	-	-	-	-	38.5	33.5	24.3	46.0	20.6
			22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
27	Associated Transactional Services Revenue		106.7	-	-	-	-	-	-	367.8	265.0	294.3	332.2	269.6
28	Transactional Services Net Revenue		84.7	-	-	-	-	-	-	329.3	231.5	270.0	286.2	249.1

BOMA INTERROGATORY #12

INTERROGATORY

Issue #2

Ibid, P18

In the recent Union decision, in EB-2011-0210, the Board decided that "90% of all optimization net revenue should accrue to ratepayers and 10% shared with Union as an incentive to continue to undertake the activities".

Does Enbridge agree that a 10% share of such revenue, is an appropriate incentive for Enbridge to continue to carry out optimization activities?

RESPONSE

EGD believes that for the purpose of clearing the 2012 Transactional Services Deferral Account ("TSDA") the sharing of Transportation Optimization should be shared 75:25 between rate payer and shareholder as was agreed to in the EB-2011-0277 Settlement Agreement. This would include those revenues generated through Capacity Release Exchanges because the Company maintains that these amounts are no different than any other type of exchange agreement and follows the Company's position that they are unplanned, a third party must be requesting service and EGD must have temporarily surplus capacity.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOMA INTERROGATORY #13

INTERROGATORY

Issue #2

Ibid, P9

Please confirm that currently Enbridge receives an incentive of ten percent and twenty-five percent, respectively, of the revenues from transactional services built into rates, and any revenue variance, respectively.

RESPONSE

For 2012 the sharing mechanism for transactional services revenue as per the ADR settlement agreement in the 2008 through 2012 IR time period, docket EB-2007-0615, was 90:10 and 75:25 rate payer and shareholder for Storage Optimization and Transportation Optimization respectively.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

BOMA INTERROGATORY #14

INTERROGATORY

Issue #2

Ibid, P8, Par. 18, Storage Optimization Transactions

Please describe in detail what the "gas loan" referred to at line 3 of paragraph 18 refers to. Please include in the explanation answers to the following questions:

(a) What are the typical terms of such gas loans? To whom are the loans typically made? Please provide percentage breakdown if several categories of borrower.

(b) What were the total amounts loaned in GJs in 2012?

(c) What was the "interest rate" on the loan - was it paid as a fee, or in gas?

(d) What was the total compensation Enbridge received for such loans in 2012? If in gas, how was the gas valued?

(e) How was such compensation calculated. On what is it based, on a percentage of the marketer's profit from taking advantage of the price spread?

(f) Is the revenue currently recorded under Transactional Services, or in what fashion is the revenue shown in the utility accounts?

(g) Is the gas that Enbridge loaned to others gas that Enbridge has title to (system gas), or does Enbridge loan gas owned by individual DP customers?

(h) What was the reason for gas loans in each year of the IRM?

(i) How much storage optimization revenue from both, and each of, "gas loans" and "storage" did Enbridge include into rates for 2012 and for each of the last five years? How much revenue did it actually receive from these activities?

RESPONSE

The reference to a “gas loan” was intended to illustrate that one counterparty would loan gas to the other for return at a future date. With respect to Storage Optimization EGD never lends gas to a third party it only receives gas from a third party. Therefore, EGD does not receive any revenues associated with storage loan deals.

Witnesses: J. Denomy
J. LeBlanc
D. Small

Throughout the IR term EGD reduced rates by a total of $8.0 million per annum relating to forecasted Transactional Services revenue split between transportation and storage. Once the actual portion of customer revenues exceeded the threshold amount of $8.0 million then amounts were recorded in the Transactional Services Deferral Account (TSDA) for future disposition.

The net revenue associated with Storage Optimization for the last five years is as follows ($ 000's)

2008	8,589.1
2009	9,850.1
2010	8,960.6
2011	3,464.5
2012	5,008.6

Witnesses: J. Denomy
J. LeBlanc
D. Small

BOMA INTERROGATORY #15

INTERROGATORY

Issue #2

Ibid, P9, Paragraph 20

Please explain in detail how Enbridge uses one of its transportation contracts to accommodate a point to point exchange of gas between Dawn and Iroquois. If there is more than one way for Enbridge to accommodate the exchange, please identify the alternative(s). I assume the exchange takes place on the same day, that is, Enbridge takes delivery of gas at Dawn, and on the same day, delivers an identical amount of gas to the other party at Iroquois.

RESPONSE

The assumption is correct. Enbridge would take delivery of gas from a counterparty at Dawn and on the same day deliver gas to that counterparty at Iroquois utilizing one of EGD's TransCanada contracts.

Witnesses: J. Denomy
J. LeBlanc
D. Small

BOMA INTERROGATORY #16

INTERROGATORY

Issue #2

Ibid, P23

Enbridge notes that in the EDA, EGD is dependent on TCPL pipeline capacity to meet peak and winter demand. This necessitates a large amount of diversion to storage, via STS service in the summer. Enbridge goes on to state:

"This need for significant diversion to storage provides the opportunity for transactional services. The size of the diversion over a period of time can allow for the capacity release exchanges (described in detail later on), with their enhanced value, to be done rather than bare exchanges, on the day, if the right conditions exist going into the storage injection season" (our emphasis).

(a)(i) Please explain in detail what "the right conditions going into the storage injection season" are, which permit capacity release transactions to be done.

(ii) What is the storage injection season?

(b) Please discuss in detail, noting the months of the year, the range of terms of the capacity released, the magnitude (in 2012) relative to the amounts directed to storage, and the method by which the gas is returned to storage. For clarity, please provide:

- The number of such capacity release exchanges conducted in 2012.
- The number of exchanges of less than one month, one month, two months, three months, and so on up to twelve months; (terms that renew monthly at assignee's option should be shown for the total term).
- The volumes for each term of assignment.
- The method in which compensation was calculated, eg. percentage of the marketer's profit, fee related to capacity, term, or path, or some other manner.

(c) Please provide the percentage of "transactional revenue" included in rates, and actually generated in 2012 from base exchanges, capacity release exchanges, gas loans, and "storage services". Is the TP storage optimization services

Witnesses: J. Denomy
J. LeBlanc
D. Small

described in paragraph 18, what is referred to as "parking services"? If not, please distinguish the terms, and discuss what the parking service is, and the revenue from such service in 2012, and where it is recorded in the accounts.

(d) Using the example of a capacity release exchange described at paragraph 28, assuming Enbridge transfers gas to the TP at Empress, and receives it back at Dawn, how does it, or its counterparty, get the gas from Dawn to Iroquois? Assuming the STS is no longer required to move the gas into storage, does it go unused? Please explain fully.

(e) How can the assignment of several months of valuable pipeline capacity be described as a "temporary surplus", or an unplanned activity?

<u>RESPONSE</u>

a) To assist with meeting peak and winter demand, EGD relies on its STS contracts with TCPL for service from Parkway to either the CDA or the EDA. The total volume that can be moved westerly in the winter time is contingent upon the amount of STS moved easterly during the previous injection season i.e., April to October, referred to as STS Credits. If the previous winter was warmer than normal then EGD would not have required all of its allotment of STS Credits allowing a level of unused credits to be rolled over to the next winter. Therefore, in this example, EGD would not need to accumulate as many STS Credits in the summer which would make a release of capacity for exchange purposes an option provided there is a willing third party to enter into such a transaction.

b) Please see Appendix C of the evidence as well as the response to Board Staff Interrogatory #10 at Exhibit I, Tab 1, Schedule 10 as well as the response to CME Interrogatories #4 and 5 at Exhibit I, Tab 5, Schedules 4 and 5.

c) Please see the response to CME Interrogatory #4 at Exhibit I, Tab 5, Schedule 4 and BOMA Interrogatory #14 at Exhibit I, Tab 2, Schedule 14.

d) An Empress to Dawn exchange deal does not include Iroquois as either a receipt or a delivery point. EGD will only nominate for the STS service that it requires on the day to balance supply and demand. If EGD is accumulating enough STS credits to satisfy its requirements for the upcoming winter then EGD can take advantage of exchange opportunities, either through a daily Base exchange or a Capacity Release to generate Transactional Services revenue that can then benefit both the ratepayer and the shareholder.

Witnesses: J. Denomy
J. LeBlanc
D. Small

e) A detailed description of how a capacity release can be described as temporary surplus and unplanned can be found at Exhibit C, Tab 1, Schedule 6, on page 16, paragraphs 31 and 32 of the evidence.

Witnesses: J. Denomy
J. LeBlanc
D. Small

CCC INTERROGATORY #1

INTERROGATORY

Ref: Ex. B/T1/S3/p. 2

Please explain, in detail, what the $5.9 million in other income is related to. What is "forgone late payment penalty revenue"?

RESPONSE

The change in other income is partly the result of the implementation and approved use of USGAAP as of 2012, which requires the reporting of amounts received from third parties as revenue which had previously been grouped in gas cost. This included amounts for the extraction of ethane, propane, butane and pentanes of approximately $5 million which fluctuates dependent on the value of these products. Additionally, as explained in the response to BOMA Interrogatory #4 at Exhibit I, Tab 2, Schedule 4, EGD has identified the derivation of $0.9 million of foregone Late Payment Penalty ("LPP") revenue in other income which is to be recovered through the clearing of the 2012 GDARCDA.

Witnesses: K. Culbert
A. Dhoot
D. Small
R. Small

CCC INTERROGATORY #2

INTERROGATORY

Ref: Ex. B/T1/S3/p. 3

Please provide a detailed calculation of the depreciation expense increase of $65.6 million.

RESPONSE

As indicated in the referenced Exhibit B, Tab1, Schedule 3, the $65.6 million increase in depreciation expense is relative to changes in property, plant and equipment ("PP&E") over a five year period, 2012 versus 2007. The part (e) explanation in that exhibit explained that the major changes in depreciation expense were relative to PP&E increases associated with five years of customer growth and system improvements, and the implementation of a new CIS system. The attached table highlights the changes in depreciation expense by asset category over the period.

Witnesses: K. Culbert
R. Small

Depreciation Expense Details
2012 Actual vs. 2007 Board Approved

Line No.		Col. 1 2012 Actual EB-2013-0046 (Note 1)	Col. 2 2007 Board Approved EB-2006-0034	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Underground Storage			
1	Crowland storage (450/459)	0.1	-	0.1
2	Land and gas storage rights (451.00)	0.8	0.9	(0.1)
3	Structures and improvements (452.00)	0.4	0.3	0.1
4	Wells (453.00)	1.9	1.3	0.6
5	Well equipment (454.00)	0.3	0.2	0.1
6	Field Lines (455.00)	1.8	1.2	0.6
7	Compressor equipment (456.00)	2.2	1.8	0.4
8	Measuring and regulating equipment (457.00)	0.4	0.4	-
9	Sub-total	7.9	6.1	1.8
	Distribution Plant			
10.	Land rights intangibles (471.00)	0.4	-	0.4
11	Structures and improvements (472.00)	2.8	2.0	0.8
12	Services, house reg & meter install. (473/474)	98.1	80.0	18.1
13	NGV station compressors (476)	0.2	0.2	-
14	Meters (478)	9.6	7.9	1.7
15	Mains (475)	111.7	82.6	29.1
16	Measuring and regulating equip. (477)	17.5	14.1	3.4
17	Sub-total	240.3	186.8	53.5
	General Plant			
18.	Lease improvements (482.50)	0.9	0.5	0.4
19	Office furniture and equipment (483.00)	0.9	1.1	(0.2)
20	Transportation equipment (484.00)	2.1	1.2	0.9
21	NGV conversion kits (484.01)	0.2	0.1	0.1
22	Heavy work equipment (485.00)	0.8	0.6	0.2
23	Tools and work equipment (486.00)	1.1	0.8	0.3
24	Rental equipment (487.70)	-	0.1	(0.1)
25	NGV rental compressors (487.80)	0.3	0.7	(0.4)
26	NGV cylinders (484.02 and 487.90)	0.1	0.1	-
27	Communication structures & equip. (488)	0.1	0.6	(0.5)
28	Computer equipment (490.00)	7.2	28.6	(21.4)
29	Software Aquired/Developed (491.00)	18.2	-	18.2
30	CIS (491.00)	12.7	-	12.7
31	Sub-total	44.6	34.4	10.2
	Plant Held for Future Use			
32	Inactive services (105.02)	0.1	-	0.1
33	Sub-total	0.1	-	0.1
34	**Total Depreciation Expenses**	292.9	227.3	65.6

Note 1: Col 1. - EB-2013-0046 - Exhibit B,T1,S3

Witnesses: K. Culbert
R. Small

CCC INTERROGATORY #3

INTERROGATORY

Ref: Ex. B/T3/S2/p. 3

Please explain why there appears to be a higher average use per customer for Rate 1? What is meant by the wording, “a favourable customer variance”?

RESPONSE

Normalized average use per customer for Rate 1 was higher than budgeted as a result of multiple factors. Lower than forecasted gas commodity prices and warmer than normal weather contributed to higher average usage pattern since customers were less sensitive to their gas consumption. As a result of better than expected employment conditions, customers put less focus on energy savings efforts, thereby resulting in higher average use than budgeted.

A favourable customer variance refers to the higher actual number of customer meters than budgeted.

Witnesses: C. Ho
S. Riccio

CCC INTERROGATORY #4

INTERROGATORY

Ref: Ex. B/T3/S5/p. 1

Please explain the $5.3 million variance in the "Miscellaneous" category of Other Revenue.

RESPONSE

The variance in the miscellaneous other revenue is partly the result of the implementation and approved use of USGAAP as of 2012, which requires the reporting of amounts received from third parties as revenue which had previously been grouped as gas costs. This included amounts received for the extraction of ethane, propane, butane and pentanes of approximately $5 million which fluctuates dependent on the value of these products. Additionally, as explained in the response to BOMA Interrogatory #4 at Exhibit I, Tab 2, Schedule 4, EGD has recognized $0.9 million of foregone Late Payment Penalty ("LPP") revenue in other income which is to be recovered through the clearing of the 2012 GDARCDA. Lastly, miscellaneous revenue decreased by approximately $0.6 million.

Witnesses: K. Culbert
A. Dhoot
R. Lei
S. Qian
D. Small

CCC INTERROGATORY #5

INTERROGATORY

Ref: Ex. B/T4/S2/p. 1

Please explain why the OEB approved Customer Care Service Charges were $83.4 million in 2007 and actual costs were $67.487 in 2012.

RESPONSE

1. The $83.4 million figure referenced in this IR was not explicitly approved by the Board. This figure was derived at a high level for internal management purposes only and represents only costs related to outsourced customer care services. The actual total Board approved cost in respect of the Company's customer care business function for 2007 was $84.4 million which was approved in the Board's EB-2007-0615 Decision dated May 15, 2008 inclusive of the anticipated true-up. A reference to this figure can be found in the Board's May 15, 2008 Decision EB-2007-0615 Appendix F, Row 16.

2. Changes in customer care costs between 2007 and 2012 were anticipated in the EB-2007-0615 Decision, Appendix F, related to the Customer Care Settlement Agreement. The Board approved figure comparable to 2007's $84.4 million, again from the EB-2007-0615 Decision dated May 15, 2008, Appendix F, Row 16, is $116.5 million. The difference between the 2007 and 2012 settlement figures was driven by customer growth, inclusion of the operating costs and capital recovery of the Company's new CIS which commenced in 2009 and the cost consequences of completing the tendering process for outsourced customer care services.

   The actual cost incurred by the Company in 2012 for the same scope of customer care activities referenced in the Board's Decision of May 15, 2008 EB-2007-0615, Appendix F (related to EB-2006-0034Customer Care Settlement Agreement) was $109.7 million. This compares favourably to the 2012 cost of $116.5 million originally forecast for 2012 and is primarily attributable to slower than anticipated customer growth over the 2008 to 2012 period; lower customer care related IT costs; and revised outsourced services costs based on 2011 re-contracting (EB-2011-0226).

Witnesses: A. Dhoot
R. Lei

CCC INTERROGATORY #6

INTERROGATORY

Ref: Ex. B/T4/S2/p. 1

Please explain the variance between Benefits (line 12) in 2007 of $21.4 million and $45.9 million in 2012.

RESPONSE

The variance of $24.5 million is a result of an increase of pension expenses of $16.7 million and an increase of $7.8 million for benefits.

This increase of pension expenses is primarily due to the funded status of the plan going from a surplus position to a deficit position where the plan surplus or deficit is the net position when comparing the fair-value of the plan assets against the actuarial assessment of the plan obligations as at a given date. An excess of plan assets over plan obligations results in a surplus, while the reverse results in a deficit. Due to the pension plan expected to be in a deficit position, Enbridge is required to fund the pension plan for an amount that represents annual employee current service costs. As such the increase from 2007 is primarily employee current service costs as a result of pension regulations requiring pension plans to be funded should the plan be in a deficit position.

Benefit costs have increased by $7.8 million from 2007. This increase is due to several factors; (1) Canada Pension Plan, Employment Insurance, and Employers Health Tax increases; (2) additional FTEs which increase benefit costs; (3) increased utilization of the benefit plans and the need for increased services given the aging workforce; and (4) higher prescription costs and dental fees.

Witnesses: R. Lei
S. Qian

CCC INTERROGATORY #7

INTERROGATORY

Ref: Ex. B/T4/S2/p. 1

Please explain why Non-Departmental Expenses (line 15) have increased from $18.3 million in 2007 to $31.6 million in 2012.

RESPONSE

The variance of $13.3 million is primarily due to increased executive salaries and Short Term Incentive Program payments for all Enbridge Gas Distribution employees. Other contributing factors include, administrative support costs, corporate memberships, consulting fees, and other general operating costs.

Witnesses: R. Lei
S. Qian

CCC INTERROGATORY #8

INTERROGATORY

Ref: Ex. B/T4/S2/p. 1

Please explain why Corporate Cost Allocations (line 16) have increased from $18.1 million in 2007 to $48.446 million in 2012.

RESPONSE

The Corporate Cost Allocation ("CAM") has increased from $27.7 million in 2007 to $48.446 million in 2012, whereas the Regulatory Cost Allocation Methodology ("RCAM") has increased from $18.1 million in 2007 to $31.6 million in 2012.

CAM refers to the allocation of costs from Enbridge Inc. ("EI") to Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") for corporate shared services acquired by the Company. The cost allocation methodology is governed by an inter-corporate services agreement between the two parties, and the Affiliate Relationships Code for Gas Utilities (the "ARC").

The Company has been receiving shared services from EI for years. As part of the 2006 Rate Case, the Company brought forward a separate corporate cost allocation methodology called RCAM. This RCAM methodology was approved by the Board in EB-2006-0034 and has been consistently applied to calculate the RCAM amounts throughout the incentive rate regulation period starting in 2008.

The RCAM methodology has been developed with the objective of meeting the regulatory requirements of the Ontario Energy Board ("Board") (as set out in the ARC Board decisions). The objective of the RCAM is to establish, in the context of Ontario regulation, the appropriate level of charges that EI allocates to Enbridge for delivering required services during a given fiscal period for recovery from ratepayers.

RCAM did not replace CAM. CAM is still used by EI to transfer costs to all its affiliates, including the Company, for internal management and performance measurement purposes. The RCAM is a service-based cost allocation methodology.

Although the methodologies used for CAM and RCAM are different, the business drivers for the 5-year increase were the same for both and they are explained below.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

The 5-year net increases in CAM and RCAM were $20.7 million, and $13.5 million, respectively. In terms of RCAM, Primary Services cost increase accounted for $6.4 million of the total 5-year increase of $13.5 million, and for the most part was contributed by the net increases in HR and Finance related services received from EI:

The increase in HR related services ($4.4 million) is largely due to:

- the higher level of support related to the enhanced leadership development program-development, such as Succession Planning, Executive Development Programs, re-launch of the Mentoring Program, re-design and implementation of the Change Management Program, the new union performance management process (advice to the organization on effectiveness and business support), as well as the impact of the change in the use of EI's departmental budget in 2010, from proxy to the approved budget;

- the higher professional consulting fees related to the enterprise-wide HR Core project, needed to continue to evolve the HR IT system and to develop new reporting capabilities, as well as to fund the additional post implementation resource requirements to maintain the functionality and capability of the new system; and

- the higher level of activities in compensation and benefits support, coupled with the impact of the change in the use of EI's departmental budget effective 2010, from proxy to the approved budget.

The increase in Finance related services ($1.5 million) is mainly due to:

- the increase in activities in the area of Capital Market Financing & Access in respect of intervention with credit rating agencies in support of the Company's ratings, resulting in the reduction in interest expense for the Company when issuing long term-debt. The provision of access to cash flow and capital rebalancing to maintain the Company's capital structure target. Finally, the impact of the change in the use of EI's departmental budget effective 2010, from proxy to the approved budget;

- increased level of support on cash forecasting, cash management and release of external debt payment for the Company, as well as settlement of various swap transactions where the Company is a counter-party;

- specific audits conducted in the risk management area, that either directly or indirectly benefitted the Company (front office review, earnings at risk review, interest rate and foreign exchange risk review, derivative accounting review and overall credit department review);

- credit assessment support for the Company, the on-going monitoring of the Company's risk exposure and the impact of the change in the use of EI's departmental budget effective 2010, from proxy to the approved budget; and

- Board of Directors Support costs have also increased partly due to the impact of the change in the use of EI's departmental budget effective 2010, from proxy to the approved budget.

General Expenses and Direct Charges cost increase accounted for the remainder of $7.1 million out of the total 5-year net increase of $13.5 million, consisting mainly of the following:

- Stock based compensation has increased by $5.9 million, mostly reflective of the increase in eligibility and stock price;

- Insurance premiums were higher in 2011 and 2012 (5-year net increase of $3.6 million from the 2007 base) reflective of the many global energy and utility incidents which have impacted all of the insurance industry in recent years. However, this increasing trend in insurance premiums for the Company has since been reversed ($8.5 million in 2012 versus $5.7 million in 2013), as a result of the restructuring of the Company's insurance policy negotiated and subsequently implemented by EI in 2013; and

- the above increases are offset by the net increase in the Direct EFS credit of $1.9 million, partly due to the impact of change in use of EI's departmental budget effective 2010, from proxy to the approved budget.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

CCC INTERROGATORY #9

INTERROGATORY

Ref: Ex. C/T1/S2/p. 3

Please explain how EGD intends to recover the $1.1 million GDARCDA amount. Please explain, specifically how the amount was derived. Which rate classes will the amount be recovered from, and on what basis?

RESPONSE

An explanation of how the $1.1 million amount for the GDARCDA was derived is provided at Exhibit I, Tab 2, Schedule 4.

As indicated in evidence at Exhibit C, Tab 1, Schedule 1, the Company is proposing clearance of the GDARCDA along with all of the other accounts listed on page 2 of Exhibit C, Tab 1, Schedule 1 in January 2014.

The GDARCDA balance is allocated to the rate classes based on the number of customers in each rate class. The allocation is shown in evidence at Exhibit C, Tab 2, Schedule 2, page 3, Column 9.

Witnesses: K. Culbert
A. Kacicnik
R. Small

4 – ENERGY PROBE

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A, Tab 2, Schedule 1, paragraph 6

The evidence states that the earliest feasible opportunity for clearance of the 2012 ESMDA and other deferral and variance accounts is at the time of the January 1, 2014 QRAM filing.

a) Does EGD propose to include interest carrying costs through to the end of 2013?

b) What is the impact on the amount to be recovered/refunded to ratepayers of this proposal as compared to the amount that would be recovered/refunded if clearance of the accounts would have been possible at the time of the October 1, 2013 QRAM filing?

RESPONSE

a) Yes, EGD proposes to include interest carrying costs calculated through the end of 2013 in the amounts requested for recovery/refund, as seen in Column 4 of Exhibit A, Tab 2, Schedule 1, Appendix A.

b) In aggregate, the total amount to be refunded to ratepayers is approximately $94 thousand higher as a result of requesting clearance January 1, 2014, as opposed to October 1, 2013. The increase is due to a net increase in the total interest amount to be refunded. As seen in Column 4 of Exhibit A, Tab 2, Schedule 1, Appendix A, total interest to be refunded in conjunction with a January 2014 clearance is $602 thousand, whereas an October 2013 clearance would result in total interest to be refunded of approximately $508 thousand. Principal balances are not affected by the timing of the proposed clearance.

Witnesses: K. Culbert
R. Small

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

a) Please confirm that the escalation factor approved in EB-2011-0277 for 2012 was 0.77% based on a GDP IPI FDD of 1.72% and an inflation coefficient (allowed % of GDP IPI FDD) of 45%.

b) What level would the escalation factor have had to be in 2012 to reduce the normalized return on equity from 9.570% to the benchmark ROE of 7.52%?

RESPONSE

a) The Company confirms that the escalation factor approved in EB-2011-0277 for 2012 was 0.77% based on a GDP IPI FDD of 1.72% and an inflation coefficient of 45%.

b) When the Company uses an ROE of 7.52% in its Revenue Sufficiency Calculation (Exhibit B, Tab 5, Schedule 1), as opposed to 8.52%, the gross revenue sufficiency becomes $40.3 million. To reduce the Approved 2012 Total Revenue of $2,519.99 million (EB-2011-0277, Interim Rate Order, Appendix A) by $40.3 million, an escalation factor of (4.06%) would have had to have been used in the 2012 IR formula.

Witnesses: K. Culbert
R. Small

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

Has EGD made any changes to the way that the earnings sharing amount has been calculated for 2012 from the methodology used for 2011 in EB-2012-0055? If yes, please describe the change(s) and why the change(s) was (were) made.

RESPONSE

No changes in methodology were made to the way the 2012 earnings sharing amount was calculated, as compared to the 2011 ESM calculation. However, as a result of the Company's adoption of U.S. Generally Accepted Accounting Principles ("GAAP"), for financial reporting purposes in 2012, additional adjustments were required to ensure utility results and the corresponding ESM calculation were derived in accordance with Canadian GAAP, which were the accounting principles in place when the IR plan was developed and approved in EB-2007-0615. The adjustments were made to comply with Issue 10.1, Part (ii), in the EB-2007-0615 Approved Settlement Agreement, which stipulates:

> *for the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;*

Witnesses: K. Culbert
R. Small

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 3

Please show the calculation of the 7.52% based on the Board approved formula using the October 2011 consensus forecast

RESPONSE

In accordance with the methodology for calculating the reference ROE for earnings sharing purposes, the ROE has been calculated using the Board's 1997 "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities".

Table 1 shows the derivation of 2012 ROE using 2011 as the starting point.

Table 1

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Yield on 10s 3 Months Out [a]	Yield on 10s 12 Months Out [a]	Average 10s Yield	Average Spread (30s-10s) [b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col 1.+Col 2.)/2		Col 3.+Col 4.	Col 5. - 3.65	0.75 x Col 6.	7.94 + Col 7.
2.30	2.60	2.45	0.63	3.08	-0.57	-0.43	7.52

Notes: 2011 Allowed ROE: 7.94 *(EB-2011-0277 Ex E T3 S1 Table 1 col 8)*
2011 Long Canada Forecast: 3.65 *(EB-2011-0277 Ex E T3 S1 Table 1 col 5)*
[a] Consensus Forecasts, October 13, 2011 survey, p. 17.
[b] Government of Canada benchmark bond yields, Bank of Canada, September 13 – October 10, 2011

Witnesses: M. Lister
S. Murray
M. Suarez

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 1, page 7

a) Please confirm that the opening CCA balances shown in column 2 are the actual final ending 2011 utility UCC balances from the 2011 tax return, adjusted to take account of non-utility related adjustments.

b) Please explain the differences between the opening CCA balances shown for 2012 with the UCC Carry Forward figures for 2011 shown in Exhibit B, Tab 4, Schedule 1, page 7 of EB-2012-0055. For example, please explain why the opening balance in CC Class 50 is shown as $7,943,625 for 2012, when the UCC Carry Forward at the end of 2011 was $12,646,065.

RESPONSE

a) The Company confirms that the opening CCA balances shown in Column 2 are derived from the actual final 2011 utility UCC balances from the 2011 tax return, adjusted to take account of non-utility related adjustments.

b) The differences between the opening UCC balances shown for 2012 in Exhibit B, Tab 4, Schedule 1, page 7 (attached), versus the carry forward figures for 2011, shown in the same exhibit in EB-2012-0055, are mainly due to differences in estimates of addition amounts into various CCA classes within the 2011 year-end financial statement process, versus the final addition amounts determined for the corporate income tax return, which was completed in the spring of the following year. Shown in Table 1 are the adds to CCA classes that occurred within the year-end estimate, the adds that occurred within the final tax return, the difference in the 2011 year-end CCA estimate versus the final tax return, and the Utility income tax and earnings / earnings sharing impact resulting from the estimate difference.

Witnesses: K. Culbert
R. Small
E. Vangelova
B. Yuzwa

Table 1

Line No.	Col. 1 CCA Class	Col. 2 CCA Rate	Col. 3 2011 Year End Estimate CCA Adds	Col. 4 2011 Tax Return Final CCA Adds	Col. 5 2011 Estimate Adds versus Final Adds	Col. 6 CRA Half Year Rule Impact on CCA Adds	Col. 7 CCA Impact	Col. 8 Income Tax/ Earnings/ Earnings Sharing Impact from CCA Difference
		%	$	$	$	$	$	$
1	51	6.00%	229,589,706	268,185,502	(38,595,796)	(19,297,898)	(1,157,874)	327,099
2	8	20.00%	5,029,342	5,319,473	(290,131)	(145,066)	(29,013)	8,196
3	10	30.00%	5,955,130	7,287,011	(1,331,881)	(665,941)	(199,782)	56,438
4	12	100.00%	29,898,337	30,821,784	(923,447)	(461,724)	(461,724)	130,437
5	38	30.00%	2,728,011	1,506,870	1,221,141	610,571	183,171	(51,746)
6	41	25.00%	16,203,000	7,170,683	9,032,317	4,516,159	1,129,040	(318,954)
7	13	various	4,660,000	575,196	4,084,804	n/a	(153,801)	43,449
8	50	55.00%	15,033,000	8,546,876	6,486,124	3,243,062	1,783,684	(503,891)
9	Total Income Tax Difference							(308,971)
10	2011 Earnings Impact (higher) from CCA difference							308,971
11	2011 Earnings Sharing Impact (higher) from CCA difference							215,311

Witnesses: K. Culbert
R. Small
E. Vangelova
B. Yuzwa

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2011 HISTORICAL YEAR

Capital Cost Allowance - Federal

Col 1 Class No.	Col 2 UCC AT Beginning of year	Col 3 Cost of Additions	Col 4 Lessor of Costs or Proceeds	Col 5 Less 50 % of net [Cols 3 - 4]	Col 6 Rate %	Col 7 CCA F2011	Col 8 UCC Carry Forward
1	2,020,987,302	0	0	0	4.00%	(80,839,492)	1,940,147,810
51	825,925,327	229,589,706	0	114,794,853	6.00%	(56,443,211)	999,071,822
2	138,025,159	0	(159,751)	(79,876)	6.00%	(8,276,717)	129,588,691
6	16,851	0	0	0	10.00%	(1,685)	15,166
8	8,880,021	5,029,342	0	2,514,671	20.00%	(2,278,938)	11,630,425
10	23,260,699	5,955,130	(130,889)	2,912,121	30.00%	(7,851,846)	21,233,094
12	13,641,256	29,898,337	(20,000)	14,939,169	100.00%	(28,580,425)	14,939,169
12	60,086,330	0	0	0	50.00%	(30,043,165)	30,043,165
17	38,261	0	0	0	8.00%	(3,061)	35,200
38	5,484,786	2,728,011	(46,014)	1,340,999	30.00%	(2,047,735)	6,119,048
41	30,715,175	16,203,000	0	8,101,500	25.00%	(9,704,169)	37,214,006
13	1,306,431	4,660,000	0	2,330,000		(249,000)	5,717,431
3	262,293	0	0	0	5.00%	(13,115)	249,178
45	1,618,999	0	0	0	45.00%	(728,550)	890,449
50	3,882,533	15,033,000	0	7,516,500	55.00%	(6,269,468)	12,646,065
52	0	0	0	0	100.00%	-	0
Total	3,134,131,423	309,096,526	(356,654)	154,369,936		(233,330,576)	3,209,540,719

Non-utility and shared asset eliminations	385,683
Utility Federal CCA	(232,944,893)

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2011	UCC Carry Forward
1	2,020,987,302	0	0	0	4.00%	(80,839,492)	1,940,147,810
51	825,925,327	229,589,706	0	114,794,853	6.00%	(56,443,211)	999,071,822
2	138,025,159	0	(159,751)	(79,876)	6.00%	(8,276,717)	129,588,691
6	16,851	0	0	0	10.00%	(1,685)	15,166
8	8,880,021	5,029,342	0	2,514,671	20.00%	(2,278,938)	11,630,425
10	23,260,699	5,955,130	(130,889)	2,912,121	30.00%	(7,851,846)	21,233,094
12	13,641,256	29,898,337	(20,000)	14,939,169	100.00%	(28,580,425)	14,939,169
12	60,086,330	0	0	0	50.00%	(30,043,165)	30,043,165
17	38,261	0	0	0	8.00%	(3,061)	35,200
38	5,484,786	2,728,011	(46,014)	1,340,999	30.00%	(2,047,735)	6,119,048
41	30,715,175	16,203,000	0	8,101,500	25.00%	(9,704,169)	37,214,006
13	1,306,431	4,660,000	0	2,330,000		(249,000)	5,717,431
3	262,293	0	0	0	5.00%	(13,115)	249,178
45	1,618,999	0	0	0	45.00%	(728,550)	890,449
50	3,882,533	15,033,000	0	7,516,500	55.00%	(6,269,468)	12,646,065
52	0	0	0	0	100.00%	-	-
Total	3,134,131,423	309,096,526	(356,654)	154,369,936		(233,330,576)	3,209,540,719

Non-utility and shared asset eliminations	385,683
Utility Provincial CCA and UCC	(232,944,893)

Witnesses: K. Culbert
R. Small

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 2

a) Please explain and show the calculation and assumptions used to arrive at the reduction in gas sales of $915.6.

b) What was the amount recovered by EGD in EB-2012-0055 related to the partial GDARCDA revenue requirement?

RESPONSE

a) For an explanation of the amounts contained within the 2012 remaining partial revenue requirement calculation of $1.1 million please see the response to BOMA Interrogatory #4 at Exhibit I, Tab 2, Schedule 4.

b) The partial 2012 related GDARCDA revenue requirement amount agreed to, approved and recovered within the EB-2012-0055 proceeding, was $2.8 million as shown in that application's evidence at Exhibit C, Tab 1, Schedule 2, page 3.

Witnesses: K. Culbert
R. Small

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 6

a) Please provide a break out of the transactional services revenues for each of 2009 through 2012 into the types discussed at pages 10 through 18.

b) Please explain the difference in base exchange revenues of $3.82 shown n Table 4 and the exchange revenue of $20.8 shown in Appendix B.

c) For each of the types of transactional services discussed, please indicate what assets are used to generate the service, such as upstream transportation contracts, EGD pipeline assets, etc. For each asset used, please explain how the costs of these assets are recovered from ratepayers and which ratepayers pay for them (for example, all ratepayers through delivery rates, or gas supply customers only through the commodity cost of gas).

d) What would be the impact on the amount to be credited to ratepayers if EGD applied the EB-2012-0055 Decision to the revenues generated in 2012? Please show all calculations and assumptions.

e) What is the impact on EGD's shareholder if EGD were to apply the EB-2012-0055 Decision to the revenues generated in 2013? Please show all calculations and assumptions.

RESPONSE

a) Please see response to CME Interrogatory Exhibit I, Tab 5, Schedule 4.

b) The $3.83 million shown on Appendix B represents a hypothetical exchange revenue. The premise was the revenue that the Company could have generated in Base Exchange revenue if the Transactional Services volume underpinning the Capacity Release Exchanges in the summer of 2012 had been transacted on the day throughout the summer of 2012. A detailed description of the assumptions can be found at Exhibit C, Tab 1, Schedule 6, page 19, para. 37.

Witnesses: J. LeBlanc
D. Small

c) The following table addresses the cost recovery of components used to generate transactional services revenues and the treatment of same revenues to ratepayers:

Cost Component	**Recovered Through**	**Ratepayers Responsible**	**TS Optimization**	**Ratepayers Credited**
Storage Storage Transportation Service (STS)	Delivery Charges	Sales (System Gas) Western T Ontario T	Storage Storage Transportation Service (STS)	Sales (System Gas) Western T Ontario T
Upstream Transportation	Transportation Charges	Sales (System Gas) Western T	Base Exchange Revenues Capacity Releases	Sales (System Gas) Western T

d) EGD has filed evidence in this proceeding which EGD believes that, for the purpose of clearing the 2012 Transactional Services Deferral Account ("TSDA"), the sharing of Transportation Optimization should be shared 75:25 between rate payer and shareholder as was agreed to in the EB-2011-0277 Settlement Agreement. This would include those revenues generated through Capacity Release Exchanges because the Company maintains that these amounts are no different than any other type of exchange agreement and follows the Company's position that they are unplanned, a third party must be requesting service and EGD must have temporarily surplus capacity.

In response to the question, please refer to Exhibit C, Tab 1, Schedule 6, Table 4 at Option 3 where the amount in question, \$4.7M, is shown as the difference between the TS Revenue column and the Ratepayer Share column.

e) EGD believes that the sharing of 2013 Transactional Services revenue should be cleared in accordance with the Settlement Agreement in EB-2011-0354.

Witnesses: J. LeBlanc
D. Small

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 1

Did EGD consider any other allocation methodology for the TIACDA balance? If so, please explain what it was and why it was rejected in favour of the DRR.

RESPONSE

As stated in pre-filed evidence at Exhibit C, Tab 2, Schedule 1, page 2, the Company proposes to allocate the TIACDA amount proportionally to the allocation of the 2012 Distribution Revenue Requirement ("DRR") for each rate class. The nature of the cost within the TIACDA balance relates to pension expense. Pension expense follows labour within Operation and Maintenance (O&M") costs. O&M costs support all facets of utility operations. Consequently, the Company is proposing that the allocation of TIACDA balance represent utility operations as a whole. From that standpoint, the DRR allocation to the various rate classes is the most comprehensive representation of the distribution of costs to each rate class.

The Company also considered the use of a Rate Base allocator to be a suitable method for allocating the TIACDA balance, given that it is also a comprehensive representation of all facets of the Company's operations. However, the DRR (which includes rate base related costs and all other expenses) allocator is available for 2012 and is the most relevant cost allocation factor for that year.

Witness: A. Kacicnik

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 2

Has EGD made any changes to the allocation of the various deferral and variance accounts to the rate classes from what has been approved by the Board in the past, other than the proposal related to the TIACDA account? If yes, please explain the difference and the reason for the change.

RESPONSE

No, the Company has not made any changes to the Board approved deferral and variance account clearing methodologies.

Witness: A. Kacicnik

CME INTERROGATORY #1

INTERROGATORY

Rebate Account ("DRA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 4

Please describe the activities which are covered by the 2012 DRA and explain how the credit balance of $940,800 is derived.

RESPONSE

The Deferred Rebate Account is a true up deferral account which records on an annual basis any amounts payable to, or receivable from, customers resulting from the clearance of accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The 2012 DRA contains a credit balance of $940,800 which remained un-cleared from the deferral and variance account balances which the Board approved for clearance within the 2011 EB-2012-0055 ESM proceeding.

Witnesses: K. Culbert
A. Kacicnik
R. Small

CME INTERROGATORY #2

INTERROGATORY

Gas Distribution Access Rule Cost Deferral Accounts ("GDARCDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 6
Exhibit C, Tab 1, Schedule 2, pages 1 to 8

Please provide a high level description of the activities which this deferral account covers and provide details of the following items which are included in the revenue deficiency calculations for the 2012 GDARCDA:

(a) The utility assets having a Rate Base value of $240,000.

(b) The negative revenues for gas sales of $915,600.

(c) The OM&A expenses of $200,200.

RESPONSE

Please see the response to BOMA Interrogatory #4 at Exhibit I, Tab 2, Schedule 4.

Witnesses: K. Culbert
A. Dhoot
B. Welsh

CME INTERROGATORY #3

INTERROGATORY

The Electric Program Earnings Sharing Deferral Account ("EPESDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 12

Please provide a brief description of the activities which this deferral account covers and provide information to show how the credit of $281,700 is derived.

RESPONSE

The New Construction Commercial group is responsible for the delivery of the High Performance New Construction Program. The new construction program provides financial incentives for qualifying participants and design decision makers to encourage the implementation of electric energy efficiency in new construction and major renovation projects. Delivery of the program is under contract with Ontario Power Authority ("OPA") and local electric distribution companies ("LDC's").

Costs and revenues are shared 50/50 within the Electric Program Earnings Sharing Deferral Account ("EPESDA") as shown in Table 1.

Table 1

High Performance New Construction Program (HPNC)	2012 Actual
Total Revenue	$ 7,771,470
Total Costs	$ 7,208,065
Net Revenue	$ 563,405
Net to EPESDA Deferral a/c	$ 281,702

Witnesses: M. Parker
E. Reimer

CME INTERROGATORY #4

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

The Board's Decision and Order in the EB-2012-0055 proceeding indicates that revenues EGD recorded in the TSDA in 2011 included the following:

• Base Exchanges of	$11.8M
• Capacity Release Exchanges	$3.0M
• STS-RAM Third Party Exchanges	$0.8M
For a total of	$15.6M

The information at Exhibit C, Tab 1, Schedule 6, Appendix B, page 1 under the heading "Transportation Optimization" indicates that EGD achieved $39.4165M of exchange related revenue in 2012. This information suggests that 2012 Base Exchange revenue was in the order of $20.8148M and up from $11.8M in 2011. Capacity Release Exchanges appear to have increased more than six fold from about $3M in 2011 to $18.6298M in 2012. In connection with this evidence, please provide the following additional information:

(a) Please describe the changes in circumstances between 2011 and 2012 which operated to produce such a significant increases in Base and Capacity Release Exchanges.

(b) Please provide the breakdown of the Transportation Optimization revenue recorded by EGD in each of the years 2008, 2009, and 2010 segregated between Base Exchanges, Capacity Release Exchanges, and STS-RAM Third Party Exchanges.

(c) Please provide the total number of exchange transactions in which EGD engaged in each of the years 2008 to 2012 segregated between Base

Witnesses: K. Culbert
M. Giridhar
J. LeBlanc
D. Small
R. Small

Exchanges, Capacity Release Exchanges and ST-RAM Third Party Exchanges.

(d) Are the amounts related to 2012 Capacity Release Exchanges, which EGD has recorded in the TSDA rather than as gas costs reductions, nevertheless, being allocated in the same proportion and to the same rate classes to whom EGD allocates its Upstream Pipeline Transportation costs? If so, then to what classes are these amounts allocated and in what proportions?

RESPONSE

a) The increase in 2012 Base Exchange revenue and 2012 Capacity Release Exchange revenue versus the comparable 2011 revenues are a result of two factors – transaction volume and price differential. As discussed in the response to FRPO Interrogatory #12 at Exhibit I, Tab 7, Schedule 12, a determining factor in whether or not a Base Exchange or a Capacity Release Exchange will be entered into is the utilization of STS throughout the winter and subsequent need to accumulate STS credits in the summer. A colder than normal winter in 2011 drove a need for more STS credits in the summer of 2011 while a warmer than normal winter in 2012 resulted in less of a need for STS credits to be accumulated in the summer of 2012 thereby permitting Gas Control to authorize more Base Exchanges and Capacity Releases in 2012. Notwithstanding that EGD was willing to enter into more exchange deals in 2012 the Company still relied upon third parties and their interest in entering into these types of transactions. From a third party perspective what determines whether or not they are interested in entering into a transaction would be based upon the market prices at the pertinent receipt and delivery points.

For example if one were to compare a 2012 Base Exchange and a 2011 Base Exchange transaction one could simply compare the market prices between two points on the day in each year. For example a look at the Iroquois spot price and the Dawn spot price for August 15, 2012 shows US$3.335/MMBTU at Iroquois and US$3.005 at Dawn or roughly a US$0.30 differential. The same two price points on the spot market on August 15, 2011 were US$4.575/MMBTU at Iroquois and US$4.470 at Dawn or roughly a US$0.10 differential of equal volume in 2012 versus 2011 would likely generate 3 times the revenue.

Witnesses: K. Culbert
M. Giridhar
J. LeBlanc
D. Small
R. Small

b) and c) Please see the attached table.

d) Confirmed - amounts are allocated in the same manner through the TSDA as they would be through gas cost reductions. The amount related to 2012 Capacity Release Exchanges is provided in evidence, at Exhibit C, Tab 2, Schedule 2, page 3, Line 1, Column 2. This total is net of the ratepayer guarantee and includes a forecast of interest on the account up to January 1, 2014. The amount is allocated to Sales and Western Transportation Service customers, in Column 2, Lines 1.1 to 1.12, of the Allocation portion of the table, as Sales and Western Transportation Service customers are those who receive Transportation Service from the Company. In this manner, the credit from TS Capacity Release Exchanges is allocated to customers in the same manner as Transportation costs are recovered through rates.

Witnesses: K. Culbert
M. Giridhar
J. LeBlanc
D. Small
R. Small

Transportation Optimization

	Base Exchanges			STS Ram			Capacity Release			Total		
	Volume	# of Deals	Asscociated Revenue ($ millions) (1)	Volume	# of Deals	Asscociated Revenue ($ millions)	Volume	# of Deals	Asscociated Revenue ($ millions)	Volume	# of Deals	Asscociated Revenue ($ millions)
2008	113,452,413	1,401	11.1	1,596,950	29	0.3	0	-	-	115,049,363	1,430	11.4
2009	99,306,548	2,033	9.1	1,768,421	26	0.5	8,055,765	2	0.5	109,130,734	2,061	10.2
2010	73,741,202	1,640	9.7	2,013,808	30	0.5	8,797,390	2	1.3	84,552,400	1,672	11.4
2011	65,013,539	2,590	11.8	1,166,439	19	0.8	8,792,832	2	3.0	74,972,810	2,611	15.6
2012	81,160,158	3,295	19.9	2,144,419	48	0.9	24,460,474	20	18.6	107,765,051	3,363	39.4

(1) excludes any associated incurred/avoided fuel costs

CME INTERROGATORY #5

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

In the evidence at para.20 of Exhibit C, Tab 1, Schedule 6, EGD provides an example of a Base Exchange where a third party has gas available at a particular point (Dawn) and needs the gas at another point (Iroquois) but does not have a way of getting the gas there. In this scenario where EGD has transportation between Dawn and Iroquois which can accommodate the exchange, EGD will provide the point-to-point exchange of the commodity with the pricing of the service linked to the commodity price spread between the two points. In connection with this example, please provide the following information:

(a) Is the "buyer" of the commodity exchange the person who has commodity at point A and needs commodity at another point B but has no way to get the commodity from point A to point B?

(b) Is the "seller" of the exchange service the person who holds commodity at point B and the transportation to support the carriage of the exchange buyer's gas from points A to B to replace the exchange seller's gas which has been provided to the buyer at point B?

(c) Please provide a copy of the contract which EGD enters into to support a Dawn/Iroquois Base Exchange and include the pricing for the service, along with a demonstration of how that pricing is derived from a commodity price spread between Dawn and Iroquois which is realistically representative.

(d) Similarly, please provide a copy of the contract which EGD would use to support an Empress/Dawn Base Exchange, whereby EGD receives a third party's gas at Empress and delivers an equivalent amount of gas to the third party at Dawn. Include with this representative contract the price which would be charged for the service based on information which is representative of a typical price spread between the two points.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

RESPONSE

a) and b) In the context described, a third party marketer who has gas at Dawn but would rather sell it at Iroquois because of a price arbitrage would be considered the "buyer" because they require some means to get that gas to Iroquois. EGD has within its TCPL FT contract the ability to deliver gas at a number of points on TransCanada's system including Iroquois (other examples may include Chippawa, East Hereford). If on the day or days EGD was planning to divert gas on TCPL back to Dawn for the purpose of injection into storage then EGD could act as a "Seller" in the sense that by giving gas to the counterparty at Iroquois and receiving gas back at Dawn on the day can also benefit from that pricing arbitrage.

c) and d) A copy of a Transactional Services Agreement can be found in Board Staff Interrogatory # 6 (Exhibit I, Tab 1, Schedule 6). As described in response to CME Interrogatory #4 at Exhibit I, Tab 5, Schedule 4 a comparison of the Dawn spot price and the Iroquois spot price on a particular day provides the value of an exchange transaction that would be completed on a particular day. As an alternative EGD may choose to enter into an exchange transaction using NGX which allows counterparties to trade gas between two points using the NGX bulletin board based on the bid and ask prices of two unknown entities (a NGX trade example is attached as Appendix A).

Capacity Release Exchange deals are also based upon price spreads but rather than the daily spot price used for the purposes of a Base Exchange a comparison of prices for the forward summer period for NYMEX, AECO basis and Dawn basis are used. Also to be taken into consideration is the value of the FT-RAM credit that a counterparty can receive if it were to leave the FT capacity assigned to them by EGD empty and move gas using TCPL Interruptible Transport to the cheapest point which would be Emerson. EGD personnel would complete an analysis as is demonstrated in the attached example, at Appendix B, at a point in time to calculate the value of a capacity release transaction.

The first step in the calculation would be to determine how much gas could be transported from Empress to Emerson by dividing the potential RAM Credit by the applicable tolls – see item k on the example.

The next step is to determine the value of that volume at Empress and at Emerson – see item #'s l and m of the example. This will determine the value a marketer could obtain by buying and selling the gas between Empress and Emerson.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

The next step is to determine the value that can be received by selling the volume provided to the counterparty at Empress versus the cost to buy the replacement or exchange volume at Dawn – see item's n and o of the example.

Item r of the attached schedule represents the net proceeds that would be available after buying and selling gas by a marketer at the various points which then is translated into a unit rate – item s.

This would represent the breakeven point or margin a marketer could obtain if they were able to do the transaction themselves – which they cannot because they do not hold the transport.

Recognizing that a marketer would not be willing to do the transaction for nothing the EGD trader is willing to accept an exchange fee for two to three cents below the value that they have calculated.

The attached table provides a comparison of 2011 and 2012 summer prices that can be used to determine the value associated with a capacity release exchange deal

Date Time	Clearing Account	Company Name	Trader	Trade Type	Trade In Error	Cash Margin	Cleared	Market	Contract Descriptio	Begin Date	End Date	Buy/Sell	Traded Volume	Total Volume	Price	Currency	Price Unit	Platform	Trade Id	SpreadIndicato	RFQ
7/9/2013 8:20	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No		Yes	NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	Next Day	10-Jul-13	10-Jul-13	Sell	-10,000	-10,000	$0.24	USD	MMbtu	ICE	50025969/50025970	Yes	No
7/9/2013 8:20	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No	No	Yes	Dawn	Next Day	10-Jul-13	10-Jul-13	Buy	10,000	10,000	$4.15	USD	MMbtu	ICE	50025970	Yes	No
7/9/2013 7:50	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No	No	Yes	Iroquois	Next Day	10-Jul-13	10-Jul-13	Sell	-10,000	-10,000	$4.39	USD	MMbtu	ICE	50021934	Yes	No

Market	Date Time	Trade Id	Reg Type	Cleared	Begin Date	End Date	Traded Volume	Total Volume	Price	Currency			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:33	50019851/50019852	FUT	Yes	10-Jul-13	10-Jul-13	3,300	3,300	$0.16	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:37	50020436/50020437	FUT	Yes	10-Jul-13	10-Jul-13	900	900	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:35	50020115/50020116	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	$0.19	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:37	50020417/50020418	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:43	50021096/50021097	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	$0.21	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:43	50021094/50021095	FUT	Yes	10-Jul-13	10-Jul-13	7,100	7,100	$0.21	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:50	50021934/50021935	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	$0.22	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:56	50022686/50022687	FUT	Yes	10-Jul-13	10-Jul-13	7,500	7,500	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 8:03	50023921/50023922	FUT	Yes	10-Jul-13	10-Jul-13	7,200	7,200	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 8:14	50025376/50025377	FUT	Yes	10-Jul-13	10-Jul-13	800	800	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 8:20	50025969/50025970	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	$0.24	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 8:20	50025967/50025968	FUT	Yes	10-Jul-13	10-Jul-13	2,000	2,000	$0.23	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:35	50020105/50020106	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	$0.19	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 8:46	50029074/50029075	FUT	Yes	10-Jul-13	10-Jul-13	3,800	3,800	$0.26	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 9:05	50030941/50030942	FUT	Yes	10-Jul-13	10-Jul-13	3,700	3,700	$0.38	USD			
NGX Phys, FP Spr (US/MM), Union-Dawn/TCPL-Iroquois	7/9/2013 7:35	50020136/50020137	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	$0.22	USD			
								Avg	$0.2219				

Capacity Release Transaction Analysis - Example

Assume a Capacity Release Exchange of 10,000 GJ

		$/GJ	$(000's)
a	FT RAM Credit	2.32342	4,972.1
		2012 Summer Prices US$/Mmbtu	2011 Summer Prices US$/Mmbtu
b	US Exchange rate	0.985	0.973
c	Empress to Emerson transport cost	0.754	0.754
d	Empress Transport	(0.334)	(0.152)
e	NYMEX	3.630	4.000
f	AECO Basis	(0.450)	(0.380)
g	Emerson Basis	0.300	0.270
h	Dawn Basis	0.275	0.330
i = e + f + g	Value of Gas @ Emerson	3.480	3.890
j = e + f + d + fuel	Value of Gas @ Empress	2.861	3.499
k = a / c / 214 days / 1.055056	Volume that can be sold at Emerson	29,205	29,205
l = k X i	Value of gas at Sold at Emerson	21,749.3	24,311.7
m = k X j	Value of gas purchased at Empress	17,879.1	21,870.0
n = 10,000 units X j	Sale of Exchange volume at Empress	5,872.7	7,183.7
o = 10,000 units X (e + h)	Purchase cost of Exchange volume at Dawn	7,920.6	8,782.7
p = l + n	Proceeds of sales	27,622.0	31,495.4
q = m + o	Cost of Replacement gas	25,799.7	30,652.7
r = p - q	Net Proceeds	1,822.3	842.7
s - r / 10,000 GJ's / 214 days	Unit Rate value of transaction - $/GJ	0.85	0.39

CME INTERROGATORY #6

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

Assume EGD has some excess FT capacity on TransCanada PipeLines ("TCPL") between Empress and Dawn, and proposes to mitigate the costs of that excess capacity by temporarily assigning the FT to a third party. In connection with this scenario, please provide the following information:

(a) Please provide a copy of all of the documentation which EGD as assignor and the third party as assignee would execute to support the assignment, together with a description of how the pricing for the assigned space would be determined, along with the information which is used to determine that pricing.

(b) Do the benefits which EGD derives from a stand-alone temporary assignment of FT capacity made to mitigate unabsorbed demand charges get recorded in a gas supply related deferral account, or in the TSDA?

(c) Assume that the FT capacity is assigned by EGD to the third party for a price equal to 50% of the value of the TCPL FT demand charge. In this scenario, please advise as follows:

  (i) Is it EGD or the assignee who pays the full demand charge to TCPL during the period that EGD's capacity is held by the assignee?

  (ii) If the assignee pays the full demand charge, then how does EGD's payment for 50% of the demand charge related to the assigned capacity recorded in EGD's books?

  (iii) Please provide a step-by-step description of the manner in which the benefit EGD receives from temporarily assigning away FT capacity is determined and then recorded in the deferral account EGD uses for such transactions.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

RESPONSE

a) The process for the assignment of capacity for a Capacity Release Exchange is the same as any other assignment of TCPL capacity such as for a Direct Purchase Agreement. Using TCPL's "Dovetail" a shipper can assign capacity to another party under TCPL's tariff. Once the assignment has been made TCPL will credit the assignor for 100% of the current approved toll and automatically charge the assignee at 100% of the same toll. In the case of an FT assignment the applicable toll in 2012 was $2.09/GJ. If the counterparty and EGD make an agreement that capacity is either assigned at a discount or a premium to the toll then it is up to the two parties to bill one another independently.

   The response to CME Interrogatory #5 at Exhibit I, Tab 5, Schedule 5, provides for the calculations that would be performed to determine the value of the Capacity Release Exchange and it would be on that basis that EGD and the counter party would agree to the value of the transaction. In the example given the value of the transaction was calculated at $0.83/GJ. This calculation would provide EGD with a benchmark when negotiating the exchange fee with the third party. If the third party were to offer to do the deal for $0.80 then that would acceptable to EGD. If we assume the agreed price was $0.80/GJ then the third party would bill EGD $1.29/GJ which would equal the difference between $2.09/GJ toll that the third party has been billed by TCPL and the agreed to exchange fee of $0.80/GJ.

   Please refer to BOMA Interrogatory #6 at Exhibit I, Tab 2, Schedule 6 for a copy of the TS Agreement.

b) Unforecast Unabsorbed Demand Charges associated with FT long haul capacity are not included in gas costs and are at risk to the Company. As such, any temporary assignment of capacity to mitigate those costs would be to the shareholder's account and do not go to the TSDA.

c) As described in part a) if EGD did an assignment of FT capacity then it would receive a credit from TCPL for 100% of the FT toll and the third party would be billed at 100% of the toll by TCPL. In this example the third party would bill EGD the equivalent of 50% of the toll, $1.045/GJ. If we assume that the assignment was for 10,000 GJ's then EGD would receive a credit from TCPL of $648,000 (10,000 GJ's X 31 days X $2.09/GJ). This amount would be credited to the TS Deferral Account. EGD would then receive an invoice from the third party for $324,000 (10,000 GJ's X 31 days X $1.045/GJ). This amount would be debited to the TS Deferral Account. The net proceeds of $324,000 would be then be shared 75:25 between the ratepayer and the shareholder.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

CME INTERROGATORY #7

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

In connection with Capacity Release Exchanges, please provide the following information:

(a) Is an Empress/Dawn Capacity Release Exchange a "bundled" transaction consisting of:

(i) A commodity exchange acquired by EGD from a third party whereby EGD delivers its own gas to a third party at Empress in exchange for the third party providing an equivalent amount of gas to EGD at Dawn; and

(ii) A concurrent capacity assignment by EGD of the capacity it held to carry its own gas from Empress to Dawn, which capacity has been rendered idle as a result of EGD's decision to use the commodity exchange provided by the third party by taking EGD's gas at Empress and providing an equivalent amount of gas to EGD at Dawn;

(b) The evidence noted in question 5 above states that EGD's engagement in a Base Exchange is prompted by the fact that the person seeking the commodity exchange has no way to get his gas from point A to point B. This situation does not prevail when EGD enters into a Capacity Release Exchange because, before acquiring the commodity exchange service from the third party, EGD does in fact have capacity to carry its gas from point A to point B. In these circumstances, please provide the following:

(i) An explanation of all of the factors which prompt EGD to decide to engage in a Capacity Release Exchange; and

(ii) Copies of all internal manuals/guidelines or other documents which describe the criteria that are to be applied by EGD personnel before engaging in Capacity Release Exchanges;

Witnesses: M. Giridhar
J. LeBlanc
D. Small

(c) The evidence at Exhibit C, Tab 1, Schedule 6, para.33 indicates that EGD's participation in Capacity Release Exchanges is not a pre-planned component of EGD's Gas Supply Planning Process. In connection with that evidence, please confirm that EGD's decisions to engage in Capacity Release Exchanges, as an alternative to itself using the capacity it holds to carry its gas from points A to B and, instead, assigning away that capacity as part of the Capital Release Exchange transaction, are decisions that are entirely within EGD's control.

(d) Please provide a copy of all contractual documents pertaining to an Emerson/ Dawn Capacity Release Exchange transaction, including documents that will show how the third party and EGD "agree on pricing that allows for a sharing of value generated by the third party having access to the FT-RAM credits" as described in para.28 of Exhibit C, Tab 1, Schedule 6. Please include in this response a detailed description of the information which the contracting parties use to derive the pricing under these transactions.

(e) Is EGD challenging the Board's 2012-0055 Decision and Order classifying as gas cost reductions the benefits EGD derives from Capacity Release Exchanges, or is EGD indifferent to the classification of the amounts?

RESPONSE

a) EGD acquires gas at Empress through monthly RFP's and daily spot purchases to ensure that it utilizes 100% of its long haul firm transportation on TCPL. As discussed previously EGD's long haul transportation to the EDA will be greater than the demand on certain days rendering that capacity temporarily surplus. EGD will continue to operate the transportation at 100% because it will still require the supply but will plan to inject the "surplus" volume into storage utilizing the STS service on TCPL that is available to FT shippers – i.e., divert gas on TCPL from the EDA to Dawn.

   The capacity Release is the same as a Base Exchange in that volumes are exchanged between two counterparties at two different receipt points on the same day. The response to CME Interrogatory #6 at Exhibit I, Tab 5, Schedule 6 describes the process of assigning TCPL capacity.

b) There are no manuals dictating the criteria that must be applied by EGD personnel before entering into a capacity release exchange. EGD personnel are expected

Witnesses: M. Giridhar
J. LeBlanc
D. Small

however, to have an understanding of the various contracts that have been entered into as a part of carrying out the supply plan that has been developed. One of those contracts is the TCPL STS contracts. The response to FRPO Interrogatory # 12 at Exhibit I, Tab 7, Schedule 12 provides an overview of planning for STS service.

c) Gas Control has the final say on whether any Transactional Service arrangement can be entered into.

d) Please refer to the response to CME Interrogatory #5 at Exhibit I, Tab 5, Schedule 5.

e) EGD has filed evidence in this proceeding in which it believes that, for the purpose of clearing the 2012 Transactional Services Deferral Account ("TSDA") that the sharing of Transportation Optimization should be shared 75:25 between ratepayer and shareholder as agreed to in the EB-2011-0277 Settlement Agreement. This would include those revenues generated through Capacity Release Exchanges because the Company maintains that these amounts are no different than any other type of exchange agreement and include the defining elements of transactional services arrangements which are that they are unplanned, a third party must be requesting service and EGD must have temporarily surplus capacity.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

CME INTERROGATORY #8

INTERROGATORY

Transactional Services Deferral Account (“TSDA”)

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

With respect to EGD’s request to be paid an incentive for engaging in Capacity Release Exchanges which operate to reduce the costs of Upstream Transportation embedded in rates, please provide the following additional information:

(a) Please explain why EGD plans and acts, to the extent possible, to mitigate the commodity costs it acquires for utility purposes without receiving any incentive payment for such activities.

(b) Does EGD accept that it has an obligation to mitigate the commodity costs of gas and other “pass-through” costs for items it acquires for utility purposes without receiving any incentive payment for discharging that obligation?

RESPONSE

a) EGD develops a supply portfolio that is presented to the Board for the review and Approval of its costs and establishment of its rates. In the discharge of the Company’s obligation to operate and load balance the distribution system, subject to weather, service interruption, system supply versus broker delivered supply and other ever changing conditions, the Company recognizes that it must operate on a day to day basis in the fulfillment its overarching obligation to its ratepayers, that being the delivery of a safe and uninterrupted supply of natural gas at a prudently incurred cost.

In the NGEIR Decision with Reasons (EB-2005-0551 dated Nov. 7, 2006, on pages 98 through 112) the Board revised the then current 25% incentive for storage-related TS revenues to a Company share of 10%, resulting in a 90/10 sharing of storage related TS deals. At that time, the Board confirmed its Decision related to the 75/25 sharing mechanism on the balance of Enbridge’s TS deals (transportation related). This Decision reinforced the understanding that the introduction of TS offerings created an incremental level of operating complexity for the Company that deserved an incentive to do so, while being undertaken to provide a benefit to the ratepayer

b) Transactional Services were established in the mid 1990's with the expectation that benefits that EGD could generate through transactions with third parties would optimize either its transportation and/or storage assets and that the bulk of those benefits would accrue back to the customer, subject to the agreement that there be an incentive for the Company to share in those benefits.

Over the IR term, the Companyhas generated over $90.0 million in revenues for the customer through Transportation and Storage optimization. In more recent years, specifically the IR term, Intervenors and the Company have agreed to that sharing mechanism as part of a Settlement Agreement.

SEC INTERROGATORY #1

INTERROGATORY

Ref: [A/2/1, App. A] Please provide a link to the application in EB-2013-0075, or advise when that application is expected to be filed. Please confirm that the Applicant is seeking clearance in this proceeding of the 2011 SSMVA, the 2011 DSMVA, and the 2011 LRAMVA, on an interim basis only, subject to true-up by the order set out in EB-2013-0075. If that is not the case, please advise the correct legal characterization of the order the Applicant is seeking in this proceeding with respect to those accounts.

RESPONSE

The Company expects to file the EB-2013-0075 application by the end of July 2013. As indicated in Exhibit C, Tab 1, Schedule 1, page 2, footnote 1, the final balances to be cleared from the 2011 SSMVA, 2011 DSMVA, and the 2011 LRAMVA will be those approved by the Board within the EB-2013-0075 proceeding. The Company anticipates that a Board Decision within the EB-2013-0075 proceeding will be received in sufficient time to allow clearance to occur in conjunction with accounts approved in this proceeding, which are being requested for clearance in January 2014.

Witnesses: K. Culbert
R. Small

SEC INTERROGATORY #2

INTERROGATORY

[B/4/2, p. 1] Please restate this table showing, where any function has been shifted to or from line 16, Corporate Cost Allocations, the impact of that shift on each affected line.

RESPONSE

In reference to EB-2013-0046, Exhibit B, Tab 4, Schedule 2, page 1 filed on May 24, 2013, effective 2012, audit fees have been reclassified from the Corporate Cost Allocations (line item 16 of the table) to the Non Departmental Expenses (line item 15 of the table) to better reflect the nature of the billing for this expense.

As requested, the Company has restated the table by moving the audit fees for 2012, in the amount of $1.46 million, back to line 16 from line 15. The restated table is attached. Everything else remains the same.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars ($ 000's)	Col. 1 Actual 2012	Col. 2 Actual 2011	Col. 3 Actual 2010	Col. 4 Actual 2009	Col. 5 Actual 2008	Col. 6 2012 Actual Over/(Under) 2011 Actual	Col. 7 OEB Approved 2007 Utility O&M
1.	Finance	$ 6,956	$ 6,196	$ 6,016	$ 5,981	$ 5,843	$ 760	$ 8,380
2.	Risk Management	569	2,459	2,141	2,865	1,695	(1,890)	1,986
3.	Customer Care Service Charges	67,487	64,190	68,742	82,042	84,583	3,297	83,493
4.	Customer Care Internal Costs	9,600	7,360	9,222	7,868	9,679	2,239	7,302
5.	Provision for Uncollectibles	9,459	21,542	11,500	17,855	16,660	(12,083)	15,105
6.	Gas Supply and GTA Project	3,990	4,246	3,999	3,661	3,794	(256)	3,754
7.	Legal and Corporate Security	5,186	4,146	1,407	1,170	1,147	1,039	1,207
8.	Operations	65,987	58,104	58,664	52,569	50,878	7,883	51,902
9.	Information Technology	33,158	30,893	30,398	22,695	21,247	2,264	21,790
10.	Business Development & Customer Strategy (excluding DSM)	14,560	15,631	18,567	14,255	13,364	(1,070)	19,118
11.	Human Resources (excluding benefits)	23,554	20,031	15,127	14,568	13,272	3,522	13,059
12.	Benefits	45,943	27,488	27,335	26,241	24,597	18,455	21,405
13.	Pipeline Integrity and Engineering	37,541	30,786	27,233	23,768	22,385	6,755	20,811
14.	Regulatory, Public and Government Affairs	16,024	14,892	15,171	13,497	13,297	1,132	15,904
15.	Non Departmental Expenses	30,164	31,130	25,822	31,332	30,258	(966)	18,307
16.	Corporate Cost Allocations (including direct costs)	49,906	43,440	36,692	34,266	32,166	6,466	18,100
17.	Total	420,082	382,534	358,036	354,633	344,866	37,548	321,624
18.	Capitalization (A&G)	(32,457)	(24,482)	(24,330)	(23,902)	(21,643)	(7,975)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	387,625	358,052	333,706	330,731	323,223	29,573	304,200
20.	Demand Side Management Programs (DSM)	28,100	26,708	25,468	24,255	23,100	1,392	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 415,725	$ 384,760	$ 359,174	$ 354,986	$ 346,323	$ 30,965	$ 326,200
22.	Regulatory Adjustments							
23.	To eliminate Corporate Cost Allocations above RCAM	(16,836)	(16,725)	(12,428)	(13,100)	(13,066)	(111)	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	-	-	(4,900)	(9,811)	-	
25.	To eliminate Conservation Services	(7,490)	(7,292)	-	-	-	(198)	
26.	2010 ESM disallowance	-	-	(500)	-	-	-	
27.	Incremental O&M Allocated to Unregulated Storage	-	(233)	-	-	-	233	
28.	Total Adjustments	(24,326)	(24,249)	(12,928)	(18,000)	(22,877)	(76)	
29.	Utility O&M	$ 391,400	$ 360,511	$ 346,246	$ 336,986	$ 323,446	$ 30,889	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations, and other utility adjustments.
2) Historical years including the 2007 OEB approved budget have been restated based on the 2012 organization structure.
3) Line 16 includes the 2012 audit fees of $1,460 which have been shifted from line 15 for trend comparison purposes

SEC INTERROGATORY #3

INTERROGATORY

[C/1/5, p. 1] Please provide a decision or settlement agreement reference for the $3 million reduction in the OHCVA threshold.

RESPONSE

The reference is contained in the EB-2007-0615 Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, page 19 (first full paragraph), as approved by the Board Decision dated March 11, 2008.

Witness: K. Culbert

SEC INTERROGATORY #4

INTERROGATORY

[C/2/1, p. 2] Please confirm that none of the pension benefits costs included in the TIACDA relate to labour costs that are capitalized for regulatory purposes. If any of those pension benefits costs are capitalized, please advise how the underlying capitalized labour costs are allocated for cost allocation purposes.

RESPONSE

Confirmed

Witnesses: S. Chhelavda
K. Culbert
B. Yzuwa

SEC INTERROGATORY #5

INTERROGATORY

[D/1/1, p. 5] Please confirm that controllable expenses (Expenses less Earnings Sharing) increased over the two years from 2010 to 2012 by 9.03% (from $742 million to $809 million). Please provide a list of the material cost drivers causing this increase.

RESPONSE

The expenses referred to in Exhibit D, Tab 1, Schedule 1 contain corporate related amounts which are not included within regulated Utility results. In addition, while depreciation expense is contained within these categories, it increases or changes annually as a result of required capital related expenditures, and its annual rate of change cannot be viewed in a similar manner as the annual rate of change within O&M expenses.

A view of Utility specific O&M and discussion around the material cost drivers of annual increase is found at Exhibit B, Tab 4, Schedule 2.

Witnesses: K. Culbert
R. Lei
B. Yuzwa

SEC INTERROGATORY #6

INTERROGATORY

[D/1/1, p. 11] Please confirm that the election to use push-down accounting has no impact on the earnings sharing amount, or any of the deferral or variance account balances, in 2012. If there were any such impacts, please provide a detailed calculation of those impacts. (For greater certainty, please confirm that the earnings to be shared with ratepayers would be the same whether or not push-down accounting was being used.)

RESPONSE

EGD confirms that the use of push-down accounting has no impact within the Utility earnings and earnings sharing calculations, nor any impact within any deferral and variance account calculations or balances.

Indication of this was given within EB-2011-0354, in response to Interrogatory Exhibit I, Issue USGAAP, Schedule 1.5, and in response to cross examination of Company witnesses as seen within Transcript volume 2, pages 60 and 61.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

SEC INTERROGATORY #7

INTERROGATORY

[D/1/1, p. 11, 29] Please confirm that when “the Company refined the methodology by which it determines discount rates” in 2012, that change had no impact on the earnings sharing amount, or any of the deferral or variance account balances, in 2012. If there were any such impacts, please provide a detailed calculation of those impacts.

RESPONSE

Confirmed.

Witnesses: S. Chhelavda
B. Yuzwa

SEC INTERROGATORY #8

INTERROGATORY

[D/1/1, p. 18] Please provide an explanation, with calculation details, of the operating costs that are capitalized for regulatory purposes and would not be capitalized “in the absence of rate regulation”.

RESPONSE

A regulated entity applying US Generally Accepted Accounting Principles Accounting Standards Codification (ASC) 980 – Regulated Operations, may defer or capitalize incurred costs to the extent it is probable that the regulator will permit recovery of the costs in future rates.

In its 2013 rate application “EB-2011-0354” Enbridge requested the use of USGAAP for rate making purposes. Enbridge identified the advantages of adopting USGAAP over MIFRS, as follows:

- alignment between financial reporting and regulatory accounting;
- transparency;
- ease of reconciliations;
- more reflective of the economic realities of regulated operations;
- greater consistency between earnings and revenue requirements;
- facilitates industry comparability;
- reduced regulatory costs; and
- reduced revenue requirement.

The Board, in its Decision on Preliminary Issue and Procedural Order No.2 dated May 16, 2012, approved Enbridge’s request to use USGAAP for regulatory purposes.

The calculation details of costs capitalized for regulatory purposes would be too onerous to provide or explain in the context of this proceeding. The capitalization of these costs goes back decades and has been approved by the Board within the annual rate setting process. The following are examples of the types of costs that are typically deferred or capitalized under ASC 980:

- Allowance for Equity used During Construction
- Pre-construction costs
- Rate hearing costs
- Regulatory deferral and variance accounts

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

SEC INTERROGATORY #9

INTERROGATORY

[D/1/1, p. 21] Please provide details of the cost, including interest, standby fees, and other costs, of the "Commercial Paper and credit facility draws", and details of the negative cost, including interest, fees and costs paid and received, of "Short-term borrowings".

RESPONSE

1. The costs associated with the commercial paper and credit facility draws are comprised of following two items:
   - Interest expense: $2.4 million
   - Standby fee $1.5 million

   The standby fee is grouped in "Other interest and finance costs".

2. In the referenced table, the amount indicated in the line item entitled "Short-term borrowings" is shown with brackets merely to mathematically demonstrate an amount to be deducted from the line above which is Total debt, in arriving at a remainder which would be the amount of Long-term debt.

Witnesses: R. Lei
B. Yuzwa

SEC INTERROGATORY #10

INTERROGATORY

[D/1/1, p. 24] Please provide a table for the years 2007-2012 showing the number of Incentive Stock Options and Performance Based Stock Options outstanding at the beginning of the year, the options granted during the year, the options exercised during the year, and the number outstanding at the end of the year.

RESPONSE

	2007	**2008**	**2009**	**2010**	**2011**	**2012***
Balance, beginning of the period	1,957,700	2,032,700	2,263,950	2,426,000	2,405,500	2,479,850
Granted	231,800	427,000	498,200	356,400	545,400	618,050
Exercised/Released	(147,150)	(191,650)	(335,400)	(376,900)	(471,050)	(520,500)
Cancelled/Forfeited	(9,650)	(4,100)	(750)	-	-	-
Balance, end of the period	2,032,700	2,263,950	2,426,000	2,405,500	2,479,850	2,577,400
*includes 169,400 Performance Stock Options granted						

Witnesses: R. Lei
B. Yuzwa

SEC INTERROGATORY #11

INTERROGATORY

[D/1/2, p. 6] Please provide an evidence reference showing where the $5 million of capital gains taxes on the sale of the Amherstburg project have been grossed-up and deducted from costs for the purposes of calculating earnings sharing.

RESPONSE

As included in evidence at Exhibit B, Tab 4, Schedule 1, pages 4 and 6 show that corporate income taxes are eliminated within the process of determining Utility earnings and within the same exhibit, Utility stand-alone income taxes are shown on page 3, exclusive of any non-utility or unregulated items such as the Amherstburg project.

Witnesses: K. Culbert
B. Yuzwa

FRPO INTERROGATORY #1

INTERROGATORY

REF: Exhibit B, Tab 2, Schedule 4, Page 1 of 4

Please provide the contributing factors to the more than 20 % increase in the system reinforcement expenditures?

RESPONSE

The increase is primarily due to significantly more reinforcement activity in terms of larger projects (i.e., greater than $500K) and smaller projects. In addition, the increased direct spend attracts an increased amount of allocated costs relative to other categories of direct capital spend. Allocations include departmental labour costs, capitalized administrative and general overheads and interest during construction. Allocations are primarily prorated to direct capital expenditures based on percentage spent. See the table below.

Table 1

Description	2012	2011	2012 Increase vs. 2011
Projects over $500K:			
GTA Reinforcement	7.8	1.5	6.3
Alliston Reinforcement	3.2	0.5	2.7
Angus Reinforcement	3.1		3.1
Sheridan Gate By pass	2.8		2.8
Ottawa Reinforcement	1.0		1.0
Kawartha Ethanol	1.8	1.1	0.7
Preston Road Cavan	1.2	0.2	1.0
Scarborough Reinforcement	0.9		0.9
Sub total Projects over $500K	**19.7**	**3.1**	**16.6**
Reinforcement Projects less than $500K	3.5	1.9	1.6
Total Reinforcement Direct Costs	**23.2**	**5.0**	**18.2**
Allocations:			
Departmental Labour costs	9.5	4.0	5.5
Capitalized Administrative and General	4.1	0.6	3.5
Interest During Construction	0.7	0.2	0.5
Summary total	**37.5**	**9.8**	**27.7**

FRPO INTERROGATORY #2

INTERROGATORY

REF: Exhibit B, Tab 3, Schedule 1, Page 5 of 5

Please break-out the components of the $27.7 M of Miscellaneous Revenue providing at least the amount from Non-utility storage.

RESPONSE

The elimination of $27.7M within net revenue, from EGDI Ontario Corporate Revenues, can be broken down into the following activities:

- $0.5M Oil and Gas Production,
- $15.8M Unregulated Storage,
- $11.4M Amherstburg Solar.

Witnesses: K. Culbert
R. Small

FRPO INTERROGATORY #3

INTERROGATORY

REF: EB-2012-0046, Exhibit C, Tab 1, Schedule 6, Page 6 of 21

Please provide all relevant internal emails, memos, correspondence and including any presentations to Senior management or EGD Board of directors that pertained to the decision not to follow the Board's decision in EB-2012-0055 ordering the treatment of FT-RAM and other upstream optimizations as reductions to gas costs.

RESPONSE

Enbridge is in complete compliance with the Board’s decision in EB-2012-0055.

The findings of the Board required Enbridge to “stream” additional 2011 capacity release revenues to ratepayers. The Board also directed Enbridge to propose a methodology for disposing of the incremental amount to ratepayers. The Company complied with both of those directives.

The Board also directed Enbridge to discuss how it proposes to dispose of 2012 capacity release net revenues in the Draft Rate Order filing. Enbridge’s proposal was to lead evidence in its 2012 ESM proceeding to support its position that 2012 net revenues from capacity release transactions are appropriately recorded in the 2012 TSDA which it has done.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #4

INTERROGATORY

REF: EB-2012-0046, Exhibit C, Tab 1, Schedule 6, Page 6 of 21

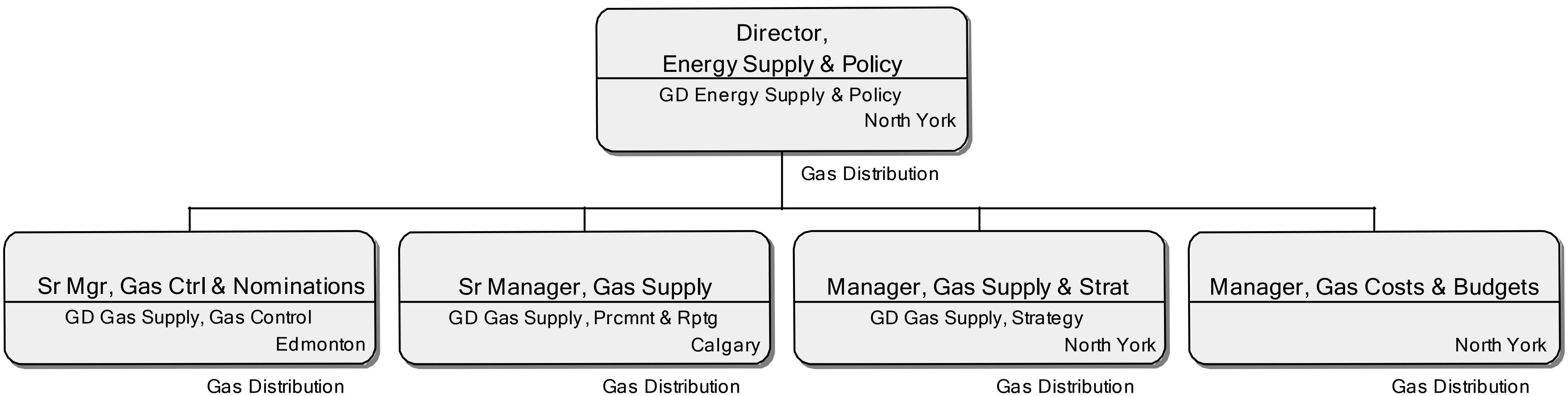
Please provide an organizational chart showing the position titles. a) Does position responsible for overall responsibility for the Gas Supply and Gas Control Group (GCG) have compensation tied to Transaction Service Margin?

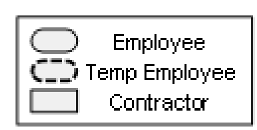
RESPONSE

Please see attached organizational chart.

The Director, Energy Supply and Policy has overall responsibiliity of the Gas Supply and Gas Control groups. There is no compensation plan unique to the Director, Energy Supply and Policy. To the extent that the Company portion of Transactional Services revenue contributes to the overall earnings of the Company, similar to any other employee, the Director, Energy Supply and Policy may benefit through EGD's compensation plan.

Witnesses: M. Giridhar
J. LeBlanc
D. Small





Current Date 7/17/2013

FRPO INTERROGATORY #5

INTERROGATORY

REF: EB-2012-0046, Exhibit C, Tab 1, Schedule 6, Page 6 of 21

During the winter months, does GCG release any monthly or weekly transport? If so, what is the longest lead time for each term prior to flow date? a) For each month of the 2012 winter, please provide the quantities of TCPL long-haul transport released by delivery area and the date released.

RESPONSE

Other than assignments of long haul FT capacity to Direct Purchase customers and the assignment of Dawn to CDA capacity in accordance with the System Reliability agreement Enbridge does not assign or release any capacity during the winter months. As discussed at Exhibit C, Tab 1, Schedule 6, page 14,para. 28 “EGD requires 100% of its contracted TCPL long haul capacity to meet peak day demand”. Please see response to FRPO Interrogatory #8.5 at Exhibit I, Issue D2, Schedule 8.5 in EB-2011-0354, attached as Appendix A, which provides a monthly breakdown for the period April 2011 to March 2012. Appendix C of Exhibit C, Tab 1, Schedule 6 in this proceeding provides a monthly breakdown for the period April 2012 to December 2012.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Please provide the detailed analysis that supports the increase in STFT.

a. Please provide the specific level of demand that would be necessitated by the results of the Design Criteria Study.

b. Please provide the specific calculations and supporting assumptions that determined the "$66.2 or $74.5 million in total of unutilized transportation cost impacts."

c. Using April 2011 to March 2012 actual values, please provide monthly values for:

   i. The quantity of daily firm transport contracted in each TCPL delivery zone.
   ii. The quantity of daily firm transport delivered to other EGD delivery zones by other providers.
   iii. The quantity of daily firm TCPL contracts optimized to generate revenue versus recovered in EGD transportation rates?
   iv. The amount of FT-RAM credits accrued.
   v. The amount of revenue generated by utilization of those credits.
   vi. The demand charges for the transportation that was optimized.

d. Please clarify where the demand charge costs were charged and to what account were the revenues accrued.

Witnesses: J. Sarnovsky
D. Small

RESPONSE

a) The 2013 gas cost was prepared assuming, among other things, a peak day demand based upon the existing Design Day Demand Criteria of 39.5 degree days which equates to a peak day demand of 99 280 10^3m^3 (3.5 Bcf). If the Board were to accept the Company's proposal for a new Design Day Demand Criteria of 43.7 degree days this would equate to a peak day demand of 108 590 10^3m^3 (3.8 Bcf). See the response to Board Staff Interrogatory #13 at Exhibit I, Issue D3, Schedule 1.13.

b) The updated evidence identifies $2.8 million as the amount of the unutilized capacity cost (Exhibit D1, Tab 2, Schedule 1, page 9, para. 2) which is calculated by applying the TCPL-FT toll times the unutilized capacity of 1,350,000 Gj's. If the Board were to accept the Company's proposed changes to the Design Day Demand Criteria then the Company would be required to contract for additional transportation to meet the increase in Peak Day Demand. As discussed in its Gas Cost evidence not all of that incremental capacity would be utilized. That incremental unutilized capacity would increase by 31,375,000 Gj's or $66.2 million.

c) The Company will re-iterate how capacity assignments and FT RAM credits contribute to Transactional Services revenue. While transactional service deals pertaining to transportation optimization utilize the utility transportation contracts, no deal will be entered into at the expense or risk of the customers of the utility. For example, during periods of reduced demand, typically during the summer months, Enbridge may optimize underutilized transportation capacity by executing basic exchanges between two points for a fee charged to a third party (i.e., Enbridge could move gas received at Dawn and redeliver to the CDA). During these same periods of reduced demand the Company may, temporarily release parts of its long haul TCPL capacity to third parties. Tied to each release is an exchange through which Enbridge generally delivers gas at Empress and receives an equivalent volume of gas at Dawn. The credit received from TCPL through the temporary assignment offset by the cost payable to the third party for the transportation capacity represents Transportation Optimization for Transactional Services purposes.

As for FT RAM these credits are only accumulated if a shipper does not utilize 100% of its RAM eligible capacity (i.e., FT or STS). In the case of Enbridge this is generated only when the Company does not fully utilize its STS capacity. For example, if in the month of December Enbridge did not fully utilize its STS capacity then we would have available credits that can be applied against the costs associated with any IT transportation costs that might be incurred by the Company in

the month of December. However if Enbridge does not contract for any IT transportation service in that month then any STS-RAM credits go unutilized as credits cannot be carried forward to a subsequent month. To the extent that the Company required IT transportation for the purposes of meeting the needs of the Utility then any STS-RAM credits received by the Company would go toward lowering the transportation costs to the benefit of the rate payer and be captured as part of the PGVA. If however, the Utility did not require any IT transportation and there was an opportunity to enter into a Transactional Services deal with a third party through the use of IT transportation then any STS-RAM credits received would offset that IT transportation cost and provide a benefit as part of the Transactional Services Transportation Optimization.

The attached table provides the daily contracted demand level of the contracts in place for the months April 2011 to March 2012. Item # 1 represents the contracted TCPL FT capacity from Empress to the CDA. Item # 2 represents the amount of CDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 3 represents the contracted TCPL FT capacity from Empress to the EDA and Item # 4 represents the amount of EDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 5 represents the amount of Empress to EDA capacity that has been released to a third-party (for purposes of this schedule only those capacity assignments that were for an entire month, were included). This is a Transactional Services arrangement that is referred to as an Empress to Dawn Exchange. Enbridge will purchase gas at Empress and as part of the exchange with the counterparty will return the gas to Enbridge at Dawn on the same day. As part of this exchange deal the Company will assign to the counterparty long-haul TCPL capacity. Enbridge will receive a credit from TCPL for the amount of the assignment which is greater than the amount being paid to the counterparty to move the gas to Dawn. For gas costs purposes the assignment is deemed to not have happened i.e., the demand charge cost and commodity cost are included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid for transport to the counterparty is recorded as Transactional Services revenue and recorded as Transportation Optimization. Item # 6 represents the one year assignment of Empress to Iroquois capacity that was mentioned as part of the Gas Supply evidence. Item #'s 7 and 8 represent the Contracted STFT amounts. Item # 9 is the level of Enbridges' contracted TCPL Dawn to CDA capacity and Item # 10 represents the amount of that capacity that has been assigned to ABM's as a part of the System Reliability proceeding. Item # 11 is the level of Enbridges' contracted TCPL Dawn to EDA capacity. Item # 12 represents the amount of the Dawn to EDA capacity that was assigned to third parties (for purposes

of this schedule only those capacity assignments that were for an entire month were included) as part of a Transactional Services deal. Similar to Item # 5 for purposes of gas costs the assignment is deemed to not have happened i.e., the demand charge cost is included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid to the counterparty is recorded as Transactional Services revenue Transportation Optimization. Item #'s 13 to 16 are the remaining transportation arrangements Enbridge has with TCPL. Item #'s 17 and 18 represent the transportation commitments the Company has with Union Gas. Item #'s 19 to 21 represent the revenue and costs associated with the release of capacity to third parties as discussed above. Item #'s 22 to 24 provide the monthly TCPL IT transportation costs and STS RAM credits incurred by the Company. These costs are further broken down between costs incurred for Utility purposes or for purposes of generating Transactional Services revenue – Item #'s 25 & 26. Item # 27 provides the Transactional Services revenue attributable to that transaction and Item # 28 provides the net revenue.

d) See response to part c)

Witnesses: J. Sarnovsky
D. Small

Item #	Transportation	Route	Contracted Daily Volume Column 1 Apr-11	Column 2 May-11	Column 3 Jun-11	Column 4 Jul-11	Column 5 Aug-11	Column 6 Sep-11	Column 7 Oct-11	Column 8 Nov-11	Column 9 Dec-11	Column 10 Jan-12	Column 11 Feb-12	Column 12 Mar-12
	GJ's													
1	TCPL FT - CDA	Empress to CDA	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA	(7,732)	(7,772)	(7,772)	(7,784)	(7,757)	(7,762)	(7,733)	(7,388)	(7,387)	(7,317)	(7,371)	(7,387)
3	TCPL FT - EDA	Empress to EDA	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970
4	Direct Purchase Assignment	Empress to EDA	(15,391)	(15,299)	(15,189)	(14,952)	(14,790)	(14,530)	(14,336)	(14,621)	(12,880)	(13,065)	(12,420)	(11,439)
5	Transactional Services Capacity Release	Empress to EDA	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois	-	-	-	-	-	-	-	26,956	26,956	26,956	26,956	26,956
7	TCPL STFT - CDA	Empress to CDA	-	-	-	-	-	-	-	50,000	175,000	250,000	250,000	125,000
8	TCPL STFT - EDA	Empress to EDA	-	-	-	-	-	-	-	-	50,000	75,000	75,000	25,000
9	TCPL FT Dawn to CDA		149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
10	Direct Purchase Assignment as per System Reliability		(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)
11	TCPL FT Dawn to EDA		114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
12	Tranasactional Services Assignment		(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	-	-	-	-	-
13	TCPL FT Dawn to Iroquois		40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
14	TCPL FT-SN Parkway to CDA		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
15	TCPL STS Parkway to CDA		284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
16	TCPL STS Parkway to EDA		80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
17	Union Gas Dawn to Parkway		2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
18	Union Gas Dawn to Kirkwall		67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000's)													
19	Transactional Services Revenue - credit received from TCPL		2,899.6	2,905.7	2,899.6	2,905.7	2,906.3	2,900.2	2,906.3	-	-	-	-	-
20	Transactional Services Expense - amount paid to counterparty		(2,413.7)	(2,494.2)	(2,413.7)	(2,494.2)	(2,494.2)	(2,413.7)	(2,494.2)	-	-	-	-	-
21	Transactional Services Net Revenue		485.8	411.5	485.8	411.5	412.1	486.4	412.1	-	-	-	-	-
22	TCPL IT costs - Before STS RAM Credits		338.7	172.7	91.5	177.6	236.5	148.3	55.8	647.3	651.4	402.4	586.7	424.0
23	TCPL STS RAM Credits		(316.5)	-	-	-	-	-	-	(608.8)	(612.8)	(375.9)	(540.7)	(398.9)
24	Net Cost		22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
25	Amount charged to Gas Cost		0.2	172.7	91.5	177.6	236.5	148.3	55.8	-	5.1	2.3	-	4.6
26	Amount charged as Transactional Services Expense		22.0	-	-	-	-	-	-	38.5	33.5	24.3	46.0	20.6
			22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
27	Associated Transactional Services Revenue		106.7	-	-	-	-	-	-	367.8	265.0	294.3	332.2	269.6
28	Transactional Services Net Revenue		84.7	-	-	-	-	-	-	329.3	231.5	270.0	286.2	249.1

FRPO INTERROGATORY #6

INTERROGATORY

REF: EB-2012-0046, Exhibit C, Tab 1, Schedule 6, Page 6 of 21

Please update (up to March 2013) and produce the table in the attachment to the response to FRPO IR in EB-2011-0354 at Issue D2 Schedule 8.6.

RESPONSE

The response to FRPO Interrogatory #D2, Schedule 8.5 provided a monthly breakdown for the period April 2011 to March 2012. Exhibit C, Tab 1, Schedule 6, Appendix C of this proceeding provided the monthly breakdown for the period April 2012 to December 2012. The information request for the 1st quarter of 2013 is not relevant in this proceeding.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #7

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 10 of 21

Please provide a table for each winter month of 2011 and 2012 showing the: total transport capacity held and the amount released including the term (seasonally, monthly, weekly, daily) and the date it was released. a) Please provide the EGD data (forecasted degree days, expected daily consumption to the market area released) that was used for the each of the capacity releases. If this request is too onerous, please provide for each term (seasonal, month, week, daily) each month, the data that supported the longest lead time between transaction and scheduled flow.

RESPONSE

As discussed in the response to FRPO Interrogatory #5 at Exhibit I, Tab 7, Schedule 5, Enbridge does not release capacity in the winter months.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #8

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 10 of 21

How much spot gas or landed gas did EGD buy in the summer of 2012 that was not supplied by a firm transportation contract (and not as a result of an assignment or exchange)?

RESPONSE

During the June 2012 to August 2012 period Enbridge purchased 20,188,758 Gj's of supply at Dawn.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #9

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 13 of 21

How does EGD recover STS costs in rates i.e. please specify who pays for the demand charges and through what rates?

RESPONSE

Storage Transportation Service is used to inject and withdraw gas from storage facilities, and is thus complementary to the Company's storage services. Since storage services are provided to all bundled customers, costs are recovered through the Company's delivery rates.

Witnesses: M. Giridhar
M. Kirk
J. LeBlanc
D. Small

FRPO INTERROGATORY #10

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 13 of 21

Please update and produce the Table generated in the attachment to EB-2011-0354 interrogatory response Exhibit I, Issue C6, Schedule 4.1 providing detail on the monthly collection of STS-RAM credits and their application to IT.

a) As an additional column to the above requested table, please provide the dollar value of STS-RAM credits applied to optimization and those that were not used.

b) Please update and produce the Summary Table in part i) of the same above interrogatory showing a summary of the use of Total RAM credits.

RESPONSE

Please see attached Table for the amount of monthly IT transportation costs and monthly STS-RAM credits. For a breakdown of the IT cost and RAM credits between Gas Costs and Transactional Services please see Exhibit C, Tab 1, Schedule 6, Appendix C.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

TCPL 2625 Interruptible Contract

2012	Total IT Cost (before tax)	Total IT RAM Credits	Net IT Cost (before tax)	Elegible RAM Credits
	$	$	$	$
January	402,430.49	375,871.91	26,558.58	375,871.91
February	586,705.36	540,715.50	45,989.86	540,715.50
March	424,047.93	398,864.51	25,183.42	417,157.69
April	228,591.71	214,707.19	13,884.52	214,707.77
May	86,582.70	-	86,582.70	-
June	38,820.00	-	38,820.00	-
July	41,408.00	-	41,408.00	-
August	58,877.00	-	58,877.00	-
September	38,820.00	-	38,820.00	-
October	7,764.00	-	7,764.00	-
November	420,410.96	342,514.98	77,895.98	342,514.98
December	470,439.84	436,565.02	33,874.82	436,565.02
	2,804,897.99	2,309,239.11	495,658.88	2,327,532.87

FRPO INTERROGATORY #11

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 15 of 21

Is the statement in the last sentence of paragraph 23 still true if EGD receives the 10% ordered in the EB-2012-0055 decision? If not, why not?

RESPONSE

The EB-2012-055 Decision directed EGD to treat capacity release exchanges as a pass through in their entirety. EGD did not receive any incentive.

If, as EGD has assumed herein, the reference was intended to be paragraph 29 on page 15 of 21, the example provided in that paragraph was to illustrate that if EGD were to leave the capacity empty to generate FT-RAM for “own use” that the benefit to the ratepayer would only be $1.86 million compared to the $14.0 million ratepayers will receive from the capacity release exchange deals that the Company entered into with various counterparties in 2012.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #12

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 17 of 21

Please provide the monthly STS withdrawal rights balance at the end of each month of the IRM period.

RESPONSE

The attached table provides the monthly STS balances for both the CDA and the EDA beginning January 1, 2008. From past experience EGD recognizes that it will require approximately 30,000,000 GJ's of STS credits in the CDA at the end of each contract year i.e., October 31 to facilitate meeting the upcoming winter demand. The table also incorporates a provision under an agreement between EGD and TCPL such that the Company is allowed to transfer credits from the EDA to the CDA to assist with meeting that 30,000,000 GJ target in the CDA.

As has been discussed, Gas Control monitors the monthly STS balances and forecasts the amount of credits that it will be able to accumulate based upon historical average summer demands. Also of consideration is the level of credits used in the current heating season and the balance that will be left to be carried over to the next year.

For example, the STS balance at the end of December 2010 coupled with the expected colder than normal winter in 2011 led Gas Control to limit the total level of Base exchanges and Capacity Release exchanges combined during the April 2011 to October 2011 period in order to maximize the amount of STS credits (see response to CME Interrogatory #4 at Exhibit I, Tab 5, Schedule 4). The opposite occurred in December of 2011 when the warmer than normal winter resulted in a lesser requirement of STS which meant lower levels of STS injection credits needed throughout the summer of 2012 which permitted Gas Control to authorize higher levels of Base Exchanges and Capacity Release Exchanges in 2012 compared to 2011.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

MONTHLY STS BALANCES

	CDA			EDA		
1-Jan-08	26,235,371			62,454,024		
31-Jan-08	21,900,865			61,740,173		
29-Feb-08	17,046,979			60,910,973		
31-Mar-08	14,074,916			60,594,624		
30-Apr-08	15,700,575			61,306,406		
31-May-08	18,779,786			62,472,728		
30-Jun-08	21,882,279			64,659,911		
31-Jul-08	25,106,558			67,027,233		
31-Aug-08	28,330,837			69,486,701		
30-Sep-08	31,426,213			71,490,011		
31-Oct-08	31,954,368			71,651,890		
1-Nov-08	42,204,368	10,250,000	Transfer from EDA	61,401,890	(10,250,000)	Transfer from CDA
30-Nov-08	39,872,773			61,205,773		
31-Dec-08	35,119,434			60,218,965		
31-Jan-09	27,167,046			59,284,755		
28-Feb-09	21,906,503			58,552,760		
31-Mar-09	19,119,559			57,755,139		
30-Apr-09	18,076,205			57,289,013		
31-May-09	19,544,404			57,285,774		
30-Jun-09	21,261,437			58,651,210		
31-Jul-09	23,355,162			60,332,255		
31-Aug-09	25,477,887			62,296,472		
30-Sep-09	27,412,387			64,368,772		
31-Oct-09	27,071,241			64,492,297		
1-Nov-09	30,000,000	2,928,759	Transfer from EDA	61,563,538	(2,928,759)	Transfer from CDA
30-Nov-09	29,144,497			61,346,039		
31-Dec-09	22,526,151			60,209,080		
31-Jan-10	15,655,516			59,203,188		
28-Feb-10	10,518,769			58,435,694		
31-Mar-10	8,582,158			57,713,323		
30-Apr-10	9,296,783			58,358,560		
31-May-10	10,904,151			60,915,111		
30-Jun-10	13,600,813			63,964,587		
31-Jul-10	16,446,658			66,303,315		
31-Aug-10	19,304,828			68,324,145		
30-Sep-10	22,011,078			70,125,749		
31-Oct-10	21,503,841			70,899,071		
1-Nov-10	30,000,000	8,496,159	Transfer from EDA	62,402,912	(8,496,159)	Transfer from CDA

30-Nov-10	27,063,739			61,924,884		
31-Dec-10	20,065,936			61,821,398		
31-Jan-11	12,809,914			60,766,165		
28-Feb-11	6,738,624			60,406,264		
31-Mar-11	1,156,770			60,140,733		
30-Apr-11	1,099,549			60,617,208		
31-May-11	3,339,899			63,760,566		
30-Jun-11	5,562,899			67,228,976		
31-Jul-11	7,883,249			70,922,946		
31-Aug-11	10,196,599			74,671,287		
30-Sep-11	12,427,099			78,233,286		
31-Oct-11	12,582,381			80,262,240		
1-Nov-11	30,000,000	17,417,619	Transfer from EDA	62,844,621	(17,417,619)	Transfer from CDA
30-Nov-11	28,797,048			63,931,270		
31-Dec-11	26,293,912			63,791,850		
31-Jan-12	21,347,613			63,536,605		
29-Feb-12	18,372,262			63,551,578		
31-Mar-12	15,734,869			64,395,694		
30-Apr-12	11,821,775			63,869,295		
31-May-12	13,609,115			65,698,346		
30-Jun-12	15,513,155			67,707,332		
31-Jul-12	17,480,663			69,720,574		
31-Aug-12	19,448,171			71,811,008		
30-Sep-12	21,198,211			73,611,100		
31-Oct-12	20,901,271			73,814,936		
1-Nov-12	30,000,000	9,098,729	Transfer from EDA	64,716,207	(9,098,729)	Transfer from CDA
30-Nov-12	24,309,612			63,804,841		
31-Dec-12	20,150,384			64,208,809		

FRPO INTERROGATORY #13

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 18 of 21

Preamble: EGD states: This option would involve no transactional service transaction and would not create any financial benefit to the ratepayer or the shareholder.

Does EGD rely on STS injections during the summer and would the first option create STS injections? a) If so, please explain why these injections are not a financial benefit to ratepayer?

RESPONSE

As discussed in response to FRPO Interrogatory #12 at Exhibit I, Tab 7, Schedule 12, EGD does rely upon STS injections in the summer to accumulate the necessary credits it will need for the purposes of STS withdrawals the following winter. In the absence of a Base Exchange entered into on the day or a Capacity Release exchange for a period in the summer EGD would continue to accumulate more and more STS credits, which do provide value, however, as the attachment to FRPO Interrogatory #12 indicates, EGD would have an ever increasing surplus of STS injections credits that it would not use.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #14

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 20 of 21

Please provide Appendix D

RESPONSE

See attached schedule.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

Item #	Empress to EDA	Total Release in the month of April 12	Total Release in the month of May 12	Total Release in the month of June 12	Total Release in the month of July 12	Total Release in the month of August 12	Total Release in the month of September 12	Total Release in the month of October 12	Total Release in the month of November 12	
		GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	
1	FT Capacity Released	2,250,000	2,643,525	2,558,250	2,643,525	2,643,525	2,558,250	2,643,525	751,290	18,691,890
	Transportation Charges	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	
2	Empress to Eastern Zone FT Demand Toll	4,788.6	5,444.7	5,444.7	5,444.7	5,444.7	5,444.7	5,444.7	1,547.4	
3	FT RAM Credit	(5,227.7)	(6,142.0)	(5,943.9)	(6,142.0)	(6,142.0)	(5,943.9)	(6,142.0)	(1,745.6)	
4	Empress to Southwest Zone IT Toll	4,685.0	5,504.5	5,326.9	5,504.5	5,504.5	5,326.9	5,504.5	1,564.4	
5	Net Transportation Cost	4,246.0	4,807.1	4,827.7	4,807.1	4,807.1	4,827.7	4,807.1	1,366.2	
6	Net Transportation Savings	542.6	637.5	617.0	637.5	637.5	617.0	637.5	181.2	
7	Avg per unit savings - $/Gj	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	
8	Additional volume that could be moved through IT (Gj's)	260,603	306,183	296,306	306,183	306,183	296,306	306,183	87,017	

	Empress to Iroquois	Total Release in the month of April 12	Total Release in the month of May 12	Total Release in the month of June 12	Total Release in the month of July 12	Total Release in the month of August 12	Total Release in the month of September 12	Total Release in the month of October 12	Total Release in the month of November 12	
		GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	
9	FT Capacity Released	808,680	835,636	808,680	835,636	835,636	808,680	835,636	-	5,768,584
	Transportation Charges	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	
10	Empress to Eastern Zone FT Demand Toll	1,675.4	1,731.3	1,675.4	1,731.3	1,731.3	1,675.4	1,731.3	-	
11	FT RAM Credit	(1,829.1)	(1,890.0)	(1,829.1)	(1,890.0)	(1,890.0)	(1,829.1)	(1,890.0)	-	
12	Empress to Southwest Zone IT Toll	1,683.9	1,740.0	1,683.9	1,740.0	1,740.0	1,683.9	1,740.0	-	
13	Net Transportation Cost	1,530.2	1,581.2	1,530.2	1,581.2	1,581.2	1,530.2	1,581.2	-	
14	Net Transportation Savings	145.2	150.0	145.2	150.0	150.0	145.2	150.0	-	
15	Avg per unit savings - $/Gj	0.1796	0.1796	0.1796	0.1796	0.1796	0.1796	0.1796	-	
16	Additional volume that could be moved through IT (Gj's)	69,732	72,057	69,732	72,057	72,057	69,732	72,057	-	
17	Total Volume that could have been transported at no charge	330,335	378,239	366,038	378,239	378,239	366,038	378,239	87,017	
18	Dawn/Empress Spread $/GJ	(0.90)	(0.76)	(0.48)	(0.81)	(0.78)	(0.56)	(0.62)	(0.75)	
19	Gas Cost Savings - $ 000's	(297.8)	(286.5)	(173.9)	(308.2)	(295.2)	(206.3)	(232.8)	(65.3)	(1,865.8)
20	Revenue from Capacity Release Exchange - $ 000's	2,446.2	2,607.3	2,759.9	2,607.3	2,607.3	2,759.9	2,508.1	334.0	18,629.8
21	Rate Payer share of Transactional Services Revenue from Capacity Release Exchanges - $ 000's									13,972.4
22	Asssumed Volume available for Base Exchanges - GJ's									24,460,474
23	Estimated Exchange fee $/GJ									0.156
24	Potential Transactional Services Revenue from Base Exchanges - $ 000's									3,821.9
25	Potential Rate Payer share of Transactional Services Revenue from Base Exchanges- $ 000's									2,866.4

FRPO INTERROGATORY #15

INTERROGATORY

REF: Exhibit C, Tab 1, Schedule 6, Page 20 of 21

Please provide Option 5 showing the impacts of using the Board approved methodology in EB-2012-0055.

RESPONSE

EGD has filed evidence which it believes supports that, for the purpose of clearing the 2012 Transactional Services Deferral Account ("TSDA"), the sharing of Transportation Optimization should be shared 75:25 between ratepayers and shareholder as was agreed to in the EB-2011-0277 Settlement Agreement. This would include those revenues generated through Capacity Release Exchanges because the Company maintains that these amounts are no different than any other type of exchange agreement and meet the defining elements of a transactional service arrangement in that they are unplanned, a third party must be requesting service and EGD must have temporarily surplus capacity.

Witnesses: M. Giridhar
J. LeBlanc
D. Small

FRPO INTERROGATORY #16

INTERROGATORY

REF: Exhibit C, Tab 2, Schedule 2, Page 3 of 6

Please provide a much more signification explanation regarding how the allocation of this cost is developed (especially for SSM and AUTVA).

RESPONSE

The accounts listed in Exhibit C, Tab 2, Schedule 2, page 3, are classified using the Board Approved methodology and factors in Columns 2 through Column 10.

The account balances in Column 8 are subject to direct allocation to the specific customer classes. In the case of AUTUVA, which only applies to Rate 1 and Rate 6, the amounts to be cleared can be found in evidence at Exhibit C, Tab 1, Schedule 3, Appendix A, page 1, Table 1, Column 11. These amounts are then directly allocated to Rate 1 ($1.75 million debit) and Rate 6 ($6.11 million credit).*

Amounts in the SSM account are allocated to each rate class in proportion to the net TRC benefits attributable to the respective rate classes, as determined by the Board Decision in EB-2006-0021.

* The amounts differ by the interest collected on the account, found in evidence at Exhibit C, Tab 2, Schedule 2, Page 2 of 6

Witnesses: A. Kacicnik
M. Kirk

Table 2 - Eastern Delivery Area Demand Summary

Eastern Delivery Area (EDA)
As per 2012 Budget

In Gigajoules (GJs)	Peak Day	Avg Winter Demand (January to March)		Avg Summer Demand (April to October)	
Demand	577,411	334,742		102,594	
Less Curtailment	(31,788)	-		-	
	545,623	334,742	(A)	102,594	(C)
TCPL FT Capacity	196,970	196,970		196,970	
TCPL STFT	75,000	75,000		-	
Direct Purchase (Ontario T-Service)	32,693	32,693		32,693	
Sub Total	304,663	304,663		229,663	
TCPL Short Haul	114,000				
TCPL STS	80,611				
Peaking Service	46,349	-		-	
	545,623	304,663	(B)	229,663	(D)
Amount Required from TCPL Short Haul and TCPL STS		30,079	(A-B)		
Amount of Long Haul required to be diverted to storage				127,069	(D-C)

24. The following is a description of the types of exchange deals that EGD has done in the last few years, including the year that is the subject of this application. A copy of a TransCanada system map has been included as an aid as certain delivery

points on their system, such as Emerson and Iroquois, and their relative position on TCPL's system are referenced in the examples (See Appendix A).

25. Base exchange – A base exchange is the simplest type of exchange. EGD gives a third party gas at one location and receives gas back from that third party at a different location on the same day. The Iroquois/Dawn exchange described earlier is an example of a typical base exchange. If for illustration the proposed exchange volume was 50,000 GJs and it was a day in July where (equivalent to the average summer day in Table 2 above) the customer demand on the day was 102,594 GJs /u
EGD would be able to complete the deal as 50,000 GJs is less than the
127,069 GJs being diverted to storage using long haul contract capacity. From a /u
gas supply plan perspective nothing has changed. 127,069 GJs gets injected into /u
storage but by doing the deal transactional services revenue is generated for the benefit of ratepayers. Base exchanges meet the elements of transactional services as they are unplanned, a third party is requesting service and EGD has adequate temporary surplus capacity.

26. STS-RAM credits exchange – To understand STS-RAM credit exchanges, STS-RAM credits themselves and how they are accumulated and consumed must first be understood. STS-RAM[1] credits are a characteristic of TCPL's Storage & Transportation Service (STS) contract service, are made available from November 15th to April 15th and arise when EGD does not fully utilize 100% of its daily contracted TCPL STS capacity. Credits can accumulate throughout the month, are only available for use within that month and can only be applied against TCPL

[1] As an aside it should be noted that the recent NEB decision, RH-003-2011, eliminates STS-RAM credits and FT-RAM credits so these transactional services opportunities will end in 2013.