OPERATING COST SUMMARY

1. This evidence shows a summary of EGD's cost of service for each of the 2013 Board Approved, and the 2014 through 2018 Fiscal Year forecasts.

Table 1
Operating Cost Summary

Line No.	($millions)	2013 Board Approved (a)	2014 Fiscal Year (b)	2015 Fiscal Year (c)	2016 Fiscal Year (d)	2017 Fiscal Year (e)	2018 Fiscal Year (f)
1	Gas costs	1,342.8	1,455.9	1,606.8	1,632.5	1,632.5	1,632.5
2	Operation and maintenance	414.9	425.3	428.5	439.5	450.5	461.8
3	Depreciation and amortization expense	279.3	262.8	276.6	303.9	313.4	322.1
4	Fixed financing cost	2.3	1.9	1.9	1.9	1.9	1.9
5	Municipal and other taxes	39.3	41.2	43.1	45.5	47.9	50.4
6	Operating costs	2,078.6	2,187.1	2,356.9	2,423.3	2,446.2	2,468.7
7	Income tax expense	51.9	33.5	13.8	4.5	8.6	15.8
8	Cost of service (excl, interest & return)	2,130.5	2,220.6	2,370.7	2,427.8	2,454.8	2,484.5

2. Explanations of the year over year changes in the operating cost items shown above is found in evidence at Exhibits D3/D4/D5/D6/D7, Tab 2, Schedule 1 and Updated Exhibit A2, Tab 3, Schedule 1.

3. Written evidence with respect to the details within each of the above forecast elements, for the 2014 through 2016 fiscal years, is found in evidence at Exhibit D1, Tabs 2 through 20.

4. The starting point for EGD's forecast total costs and expenses, standard and accepted regulatory and non-utility adjustments, and utility income tax calculations can be found at Exhibits D3, D4, D5, D6, & D7, Tab 1.

Witness: K. Culbert

2014 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 Gas Distribution”) during the 2014 Fiscal 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 Fiscal 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.

Witnesses: J. Denomy
D. Small

- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company's contracted capacity on the Vector Pipeline.
- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn Hub.
- Niagara Supply: These supplies are forecasted to be acquired at the Niagara Import/Export point.

Enbridge Gas Distribution 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 2014 gas supply arrangements.

3. The following is Enbridge's forecast of gas supply acquisition during the 2014 Fiscal Year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	4 833.0	170.6
Ontario Production	0.7	0.0
Peaking	36.1	1.3
Chicago Supply	1 847.1	65.2
Delivered Supply	932.8	32.9
Niagara Supply	0.0	0.0
	7649.7	270.0

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 January 31, 2013 to February 28, 2013 for the 12 months commencing January 1, 2014 (Exhibit D3, Tab 3, Schedule 4) and applied these monthly prices to the 2014 budgeted annual volume of gas purchases.

7. In an effort to isolate the impact of commodity cost changes the Company removed the impact of the updated price forecast and the April 1, 2013 QRAM prices in a fashion similar to that used in the determination of the 2013 gas cost budget that was filed in EB-2011-0354.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2014 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2014 PGVA. While the Company has prepared the 2014 forecast assuming that it will be acquiring gas in 2014 via traditional transportation paths (ie TCPL, Alliance/Vector) the

possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, Renewable NG, etc).

Peak Day Coverage

9. In EB-2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed in EB-2011-0354, at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2014 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Based upon the information that was available at the time Enbridge is currently forecasting a design peak day level of 105 103 10^3m^3 (3.7 Bcf) during the winter season of the 2014 Fiscal Year.

10. The Company has chosen to maintain the same level of Peaking Services for 2014 as was forecast for 2013. Unlike 2013 however, when the Company chose to rely principally on TCPL STFT service, to meet the 2014 Peak Day Demand the Company has looked to other possible solutions. The driver for this decision is based upon recent events at the National Energy Board (“NEB”). On March 27, 2013 the NEB issued its decision in TransCanada PipeLines Limited (“TransCanada”) Compliance Filing RH-003-2011. Subsequent to that decision TransCanada filed a Review and Variance Application for 2013 to 2017 with the NEB on May 1, 2013 in relation to RH-003-2011. On June 11, 2013 the NEB rendered its decision dismissing in its entirety TransCanada’s Review and Variance Application. On June 12, 2013 TransCanada issued a news release stating their disappointment with the NEB decision and that they were considering all their options including the potential for an appeal. The June 11, 2013 NEB decision also stated that TransCanada must re-file its Tariff

Witnesses: J. Denomy
D. Small

Amendments by June 17, 2013 and that they will be considered as a separate application which will be heard as part of an oral hearing to commence September 3, 2013.

11. The expectation is that the Tariff Amendments that TransCanada proposed as a part of its Review and Variance Application will be the subject of the oral hearing mentioned above. The amended Tariff provisions are intended to provide TransCanada the flexibility required to capitalize on market opportunities for discretionary services as they arise. For example, the current Tariff provisions related to posting STFT availability stipulate that TransCanada post available STFT capacity for five banking days during January 1 to 15 for the Summer Period (April 1 to October 31) and for five banking days during July 1 to 15 for the Winter Period (November 1 to March 31). For the Summer Period, monthly blocks of STFT capacity are posted for five banking days during January 16 to 31 and for the Winter Period, monthly blocks of STFT capacity are posted for a five banking days during July 16-31. TransCanada is proposing to change the five banking day requirement to a period to be determined by TransCanada but no less than one day and could occur at any time.

12. Planning for STFT in such an environment would be difficult as the availability of this service might not be known until immediately prior to the period for which it is required. In addition, the minimum bid floor would most likely be set at a level higher than the FT toll during the periods that the Company would require STFT that is during the winter months when demand for this service is high. In order to ensure that it has the transportation assets in place to meet peak day demand in the EDA, the Company intends to contract for incremental long haul TCPL FT

capacity to the EDA as opposed to principally relying upon STFT in the winter of 2014.

13. As for the CDA, there are other options available to the Company to meet its peak day requirements. The Company has an agreement in principle with a third party to provide services to EGD in the CDA for the winter of 2014 which will supplement STFT service. The availability and cost of STFT in the CDA as well as concerns regarding TCPL Mainline capacity leads the Company to believe that it may need to rely more on long haul FT capacity in the CDA in the future. The Company intends to continue to monitor the availability of transport to the franchise and to look for alternatives that will provide value to the customers of EGD while still providing safe and reliable service. If alternatives are found then any differences from the cost of those services and those forecasted as part of the 2014 gas cost will be captured in the 2014 Purchased Gas Variance Account (PGVA). A breakdown of the peak day requirement and supply forecast is shown at Exhibit D3, Tab 3, Schedule 3.

14. Based upon the 2014 volumetric forecast and the level of transportation services to meet peak demand in 2014, the Company is forecasting $30.4 million in cost consequences associated with unutilized transportation capacity. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the April 2013 QRAM. As a part of the Settlement Agreement in EB-2011-0354 parties also agreed to the establishment of the Design Day Criteria Transportation Deferral Account (DDCTDA) for 2013 and 2014. The Company's interpretation of the 2014 DDCTDA is that it should only capture the unutilized transportation costs in 2014 that are related to the increase in the Design Day Peak Demand in 2014 in comparison to 2013. Based upon its forecasted gas

costs (see Exhibit D3, Tab 3 Schedule 1, p. 2) the Company is forecasting to charge $17.2 million of unutilized transportation costs to gas cost in 2014 and $13.2 million to the 2014 DDCTDA.

15. As in prior decisions the Company is entitled to capture, as part of its gas cost forecast the cost consequences of any forecasted unutilized long haul TCPL transportation costs. For 2014 this amount translates to $17.2 million and these costs are included as part of the forecasted Storage and Transportation charges that can be found at Exhibit D3, Tab 3, Schedule 2, page 1, line Item # 6. Traditionally changes versus the forecast of these costs would not be eligible for capture and recovery within the current PGVA as previously defined. The Company is currently allowed, however, to include in the PGVA the impact of changes in TCPL tolls on any forecasted UDC (unutilized demand charge) amount.

16. In this application, the Company is proposing a change to the 2014 and subsequent years' PGVA methodology. Because of the uncertainty arising from the most recent TCPL decision and the impacts that it will have on the services the Company may or may not have at its disposal to meet its peak day requirements, the Company has chosen a conservative approach in preparing the 2014 gas costs, by the inclusion of incremental FT to the EDA. If, however, prior to the start of the fiscal year, the Company is able to enter into alternative arrangements that impact the amount of unutilized transportation capacity, the current PGVA methodology has no mechanism to capture those changes. The Company is proposing that if any alternative arrangements are subsequently entered into, then those arrangements would be included in the January 2014 QRAM Reference Price calculation and any variation between the forecasted

UDC costs included in gas costs and the actual amount should be captured in the PGVA. These amounts could also be included as part of the PGVA clearance mechanism in the January 2014 QRAM.

Transportation

17. 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 2014 fiscal year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast, contracts were priced based upon current tolls and contracts if they had an expiry date during the Test Year and were deemed to be renewed with the following exception. As discussed earlier, the Company has included as part of its 2014 Gas Cost forecast an incremental level of FT service to the EDA. It is contemplated that the Company will acquire 175,000 GJ/day of TCPL FT-NR effective November 1, 2013 for two years expiring October 31, 2015. The inclusion of the incremental long haul capacity, while assisting with the ability to meet peak day, will also lower the overall Dawn discretionary requirement in the summer of 2014.

A copy of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.

18. For the purposes of the 2014 Fiscal Year the Company has assumed the assignment of 42,500 Gj/day of TCPL short haul capacity to Direct Purchase

customers and will acquire 42,500 GJ/day of TCPL STFT from November to March.

19. 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, 2013 Union tolls.

Storage

20. 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.

21. 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. All three of these contracts have expired and effective April 1, 2010 all of the Company’s contracted third party storage is at market based rates.

22. During 2013 the Company will be required to issue an RFP for a storage contract that will expire March 31, 2014. For purposes of the 2014 forecast, the cost

impacts of the current contract are assumed to be continued in the forecast for 2014 gas costs.

Energy Content

23. 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.

UPDATED EVIDENCE

24. The Company has updated its Gas Cost forecast for 2014 to incorporate the October 2013 QRAM prices as filed in EB-2013-0295[1]. Please see the update to Exhibit D3, Tab 3, Schedule 1, pages 1 and 2 as well as Schedules 2, 3, 4 and 5.

25. In the original evidence filed at Exhibit D1, Tab 2, Schedule 1 in EB-2012-0459 the Company had expressed concerns regarding TransCanada PipeLine's ("TCPL") Review and Variance Application and the potential impact on tolls of any Tariff Amendments proposed by TCPL as a part of that Review and Variance Application. More specifically EGD was concerned with the availability and cost of STFT service which the Company had relied upon in recent years to assist it in meeting the peak day requirement of our customers.

26. Enbridge prepared its original 2014 supply portfolio based upon the assumption that it would acquire STFT at a cost equivalent to the TCPL FT toll as was the case in TCPL tolls previously. Included within the 2014 supply portfolio was a total of 257,500 GJ of STFT service (Empress to CDA) to assist in meeting the peak day requirement, as seen at Exhibit D1, Tab 2, Schedule 2, page 1. Part of that STFT service was intended to meet the increased demand resulting from the change in Peak Gas Day Design Criteria that was agreed in the 2013 rates proceeding (EB-2011-0354) to be phased in over two years (2013 and 2014).

27. Subsequent to the preparation of the 2014 gas supply portfolio, the NEB approved new tolls and provided TCPL with the opportunity to charge what it believed would be a market price for STFT. For example, TCPL is currently

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[1]As adjusted to reflect the application of the FT unit price in TCPL's July toll against the STFT volumes in the 2013 Gas Supply Plan as indicated in the referenced Oct-2013 QRAM application EB-2013-0295.

Witnesses: J. Denomy
D. Small

asking for a minimum bid floor price for STFT equal to 260% of current FT toll price. That service would run from November 1st to March 31st (151 days).

28. In July 2013, Enbridge began to explore its requirement to contract for 2014 capacity to meet the system reliability agreement requirements pertaining to the replacement of the Dawn to CDA short haul capacity that is assigned to agents of mass market customers. The System Reliability Settlement Agreement (EB-2010-0231) provides for Enbridge to assign short haul firm transportation capacity to agents for mass market customers and to replace the assigned capacity with an equivalent volume of STFT capacity from Empress, Alberta. The System Reliability Settlement Agreement goes on to state that the cost consequences of this aspect of the Agreement will be recovered from sales and Western T-service customers allocated by volume, pursuant to the Board-approved cost allocation and rate design methodology. The volume of STFT service that Enbridge would have acquired effective November 1, 2013 pursuant to these provisions of the System Reliability Settlement Agreement is 38,000 GJ/day.

29. On July 12, 2013 Enbridge sent a letter to the Board and to interested parties informing them of Enbridge's intent to acquire FT transportation to meet the above requirement, instead of five months of STFT. Given the higher tolls for STFT service than for FT service, Enbridge would have had to pay more to acquire 38,000 GJ/day of STFT for five months than to acquire the same volume of FT for 12 months. The estimated annual savings were approximately $4.5 million. This projected savings was based upon the minimum floor bid price for winter STFT at that time which was posted as 290% of FT toll. Enbridge subsequently contracted for 38,000 GJ/day of FT capacity from November 1, 2013 to October 31, 2014.

Witnesses: J. Denomy
D. Small

30. Subsequent to the filing of that letter the Company continued to look for alternatives to meeting the outstanding peak day requirement. Enbridge was able to enter into an arrangement with a third party to provide 50,000 GJ/day of capacity to the CDA for the winter period at a price that is less than the updated STFT toll.

31. This left a remaining 170,000 GJ/day of STFT capacity, of the planned 257,500 GJs/day, still to be acquired by the Company to meet its peak day obligations.

32. EGD sent a second letter to the Board and interested parties dated August 30, 2013 identifying the various options available to Enbridge. The viable options were to contract for 5 months of STFT at a toll equivalent to 260% of the current FT toll or to contract for 1 year of FT long haul capacity.

33. Based upon the information available at the time the Company determined that the preferred option would be to acquire 170,000 GJ/day of FT capacity which would be at a lower overall annual cost than acquiring an equivalent amount of STFT capacity. However, as explained in the August 30th letter, there will be Unabsorbed Demand Costs ("UDC") associated with the unutilized capacity arising from this FT capacity.

34. A portion of the STFT capacity that Enbridge seeks to replace with FT capacity relates to increased capacity requirements to meet Enbridge's updated Peak Gas Day Design Criteria. The Board-approved Settlement Agreement in EB-2011-0354 (Enbridge 2013 Rates, Issue D.3) set out the agreement of parties that Enbridge would increase its Peak Gas Day Design Criteria to reflect a 1 in 5

recurrence interval and the peak day degree days associated with this recurrence interval. It was agreed that the resultant change to heating degree days would be increased equally over the 2013 and 2014 years. The EB-2011-0354 Settlement Agreement noted that, in order to meet the increased requirements, Enbridge would have to acquire increased transportation capacity. The EB-2011-0354 Settlement Agreement went on to set out the agreement of parties that the cost consequences of unutilized transportation capacity related to this incremental transportation capacity would be recorded in the 2013 and 2014 Design Day Criteria Transportation Deferral Account ("DDCTDA").

35. Enbridge requires an additional 85,000 GJ/day of winter capacity to accommodate the change in Peak Gas Day Design Criteria. Some of that capacity (approximately 10,500 GJ/day) is required for the EDA and was forecast to be filled through FT service. The balance of the capacity (approximately 74,500 GJ/per day) is required for the CDA, and had been forecast to be filled through STFT service. The acquisition of FT service, rather than STFT service, to meet the increased transportation requirements resulting from the change in Peak Gas Day Design Criteria means that, although transportation costs will be less, there will be unutilized transportation capacity not just over three months of STFT service as had previously forecast for the CDA, but over the one-year period of FT service commencing on November 1, 2013. Enbridge proposes that all UDC associated with the acquisition of FT service effective November 1, 2013 to meet requirements resulting from the change in Peak Gas Day Design Criteria be recorded in the 2014 DDCTDA.

36. Subject to the decision ultimately reached by the Board in this proceeding regarding the Company's gas volume forecast, the forecast UDC to be recorded in the 2014 DDCTDA is approximately $41.5 million. Details of that amount are

set out in the chart at the end of this updated evidence. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2014 DDCTDA and the results of Enbridge's best efforts to mitigate such UDC will be reflected in the amounts recorded in the 2014 DDCTDA.

37. In addition to the UDC that will be recorded in the 2014 DDCTDA, there will be other UDC associated with the acquisition of FT service, effective November 1, 2013, instead of STFT service. The volume of FT capacity that will give rise to this UDC is approximately 133,000 GJ/day (which is equal to the total amount of STFT being replaced less the amount related to the change in Peak Gas Day Design Criteria). The amount of this UDC is currently forecast to be $62.8 million, subject to the decision ultimately reached by the Board in this proceeding regarding Enbridge's gas volume forecast. Details of that amount are set out in the chart at the end of this updated evidence.

38. Acquiring FT capacity to fill the remaining capacity of requirements to meet peak day demand is the preferred option due to the overall lower annual cost. However, under the current regulatory framework for Enbridge the Company is not able to recover unutilized transportation costs unless they are forecast and included within gas costs, or unless the costs can be included within the DDCTDA or another deferral account.

39. Enbridge does not propose to recover the $62.8 million of UDC (or such other revised amount as may result from the Board's decision regarding the gas volume forecast) in 2014 rates. Instead, Enbridge proposes to establish a new deferral account, called the 2014 Unabsorbed Demand Charges Deferral Account ("2014 UDCDA") to record this UDC that is in addition to the UDC to be

recorded in the 2014 DDCTDA. A description of the proposed UDCDA is filed in the updated evidence at Exhibit D1, Tab 8, Schedule 1.

40. The reason for this proposed approach is that Enbridge does not know what level of UDC will actually be incurred in 2014, because it is not yet known how much of the forecast unutilized capacity will actually be unused, nor whether some of the associated costs can be mitigated in other ways. During the winter or summer months if the Company requires this capacity for either satisfying customer demand and/or filling storage then this would also eliminate an associated level of unutilized transportation cost. The Company might also choose to use the FT service to displace discretionary gas purchases at Dawn. Another possibility of mitigating this cost may come during the summer of 2014. Unlike a Transactional Service exchange deal, whereby the Company purchases gas with the intent of injecting that gas into storage, this capacity is excess and the Company would not be buying gas to fill it. If the Company were to assign this capacity to a third party any monies received from that assignment will be used, in their entirety, to offset the unutilized transportation costs. The ability to assign capacity to a third party is a service attribute available to FT service and not to STFT service.

41. Given the uncertainty of the actual amount of unutilized transportation costs in 2014 the Company believes that the recovery of these costs should be deferred until such time that the actual costs are known. This would be accomplished through the proposed deferral account, along with the 2014 DDCTDA.

42. Enbridge will use its best efforts to mitigate the amount of UDC that would otherwise be recorded in the 2014 UDCDA and the 2014 DDCTDA and the results of Enbridge's best efforts to mitigate such UDC will be reflected in the

amounts recorded in the 2014 UDCDA and the 2014 DDCTDA. The amount recorded in the 2014 UDCDA will not be greater than the forecast amount of $62.8 million (or such other revised forecast amount as may result from the Board's decision regarding the gas volume forecast), but it may be less as a result of Enbridge's best efforts to mitigate UDC.

43. Additionally, the Company acknowledges that aspects of its 2014 gas supply plan are based on matters within its Customized IR application that are not yet approved (for example, 2014 heating degree days, average use, volumes and customer additions). The amount to be cleared from the 2014 UDCDA and the 2014 DDCTDA will recognize the implications of the Board approved volume forecast for 2014 that is established through this proceeding.

44. The Company proposes that as part of the QRAM process throughout 2014 it will provide an update as to the actual level of unutilized transportation costs and then either within the April 2015 QRAM application or at the time of the clearance of the 2014 ESM deferral account the Company would bring forward the actual 2014 unutilized transportation cost (as set out in the DDCTDA and the UDCDA) for disposition to customers either through a onetime charge or via a Rider mechanism to be collected over the subsequent 12 months.

45. Enbridge held a Consultation Meeting on October 2, 2013 to explain and discuss its updated gas supply contracting plans. All parties to this proceeding were invited to participate. In advance of the Consultation Meeting, Enbridge provided stakeholders with explanatory materials, setting out details about Enbridge's proposed updated 2014 gas supply plan, including the savings to ratepayers as compared to the as-filed gas supply plan and the increased forecast UDC resulting from an increased amount of FT capacity.

Witnesses: J. Denomy
D. Small

46. Following the Consultation Meeting, Enbridge prepared and provided a draft version of this updated evidence setting out and explaining the updated 2014 gas supply plan, and the proposal for the 2014 UDCDA.

47. During the Information Session in this proceeding held on October 11, 2013 pursuant to Procedural Order No. 2, Enbridge and parties discussed the draft version of updated evidence regarding the 2014 gas supply plan, the proposal for establishment of the 2014 UDCDA, and the proposal for use of the updated 2014 gas supply plan in QRAM applications. Enbridge's discussions with intervenors continued after the Information Session and the additional items discussed are addressed within this updated evidence.

48. One of the items that arose from the additional discussions was a request for Enbridge to provide further detailed information about the forecast UDC impacts of the acquisition of the STFT service instead of FT service, and about the forecast UDC impacts of the changes in Peak Gas Day Design Criteria. Set out at the end of this updated evidence is a chart containing the requested information. Also provided, as requested, is Enbridge's forecast of heating degree days for each month in 2014 (for the EDA, CDA), as well as Enbridge's forecast of the discretionary supplies that will be purchased at Dawn during the summer of 2014.

49. Another requested item relates to the impact of warmer than forecast weather on the forecast level of Dawn Discretionary supply that would be required. Enbridge has done some estimation calculations that can be used for sensitivity analysis purposes. These estimates are based upon volumetric forecasts as filed, meaning that any changes to the demand forecast (including the degree day

forecast and other assumptions underpinning the demand forecast) could impact the supply plan and the sensitivity calculations.

50. Currently, there is approximately 18 Bcf of Dawn Discretionary supply forecast within the 2014 gas supply plan. Assuming that the 2014 winter weather is exactly as forecast, then that volume would be available to mitigate the forecast level of UDC, in the event that Enbridge decided to refrain from buying Dawn discretionary supply and instead acquired the same volume at Empress and transported it to Dawn using surplus TCPL FT capacity. However, if winter weather is warmer than normal, then the required amount of Dawn Discretionary supply will be reduced. Enbridge estimates that if the level of Heating Degree Days (HDD) in the winter of 2014 (January to March) is 5% lower than forecast, then winter demand would decline by approximately 6.8 Bcf. Consequently the level of required Dawn Discretionary supply will be reduced to approximately 11 Bcf, as compared to the current forecast of approximately 18 Bcf. On an approximate basis, for each 1% reduction in the level of HDD, the level of forecast Dawn Discretionary supply will be reduced by around 1.4 Bcf.

Witnesses: J. Denomy
D. Small

Forecasted Monetary Impacts by Delivery Area														
$ millions														
UDCDA														
- CDA	44.0													
- EDA	18.8													
	62.8													
DDCTDA														
- CDA	36.2													
- EDA	5.3													
	41.5													
Forecasted Monthly Unutilized Capacity by Delivery Area														
PJs (millions of GJs)														
	January	February	March	April	May	June	July	August	September	October	November	December		
UDCDA														
- CDA	4.250	3.740	4.590	1.950	2.015	1.950	2.015	2.015	1.950	2.015	1.603	-		28.093
- EDA	2.125	1.870	4.077	0.450	0.465	0.450	0.465	0.465	0.450	0.465	0.330	-		11.612
	6.375	5.610	8.667	2.400	2.480	2.400	2.480	2.480	2.400	2.480	1.933	-		39.705
DDCTDA														
- CDA	1.863	1.639	2.012	2.235	2.310	2.235	2.310	2.310	2.235	2.310	1.639	-		23.095
- EDA	0.263	0.231	0.284	0.315	0.326	0.315	0.326	0.326	0.315	0.326	0.231	-		3.255
	2.125	1.870	2.295	2.550	2.635	2.550	2.635	2.635	2.550	2.635	1.870	-		26.350
Total														
- CDA	6.113	5.379	6.602	4.185	4.325	4.185	4.325	4.325	4.185	4.325	3.242	-		51.188
- EDA	2.388	2.101	4.361	0.765	0.791	0.765	0.791	0.791	0.765	0.791	0.561	-		14.867
	8.500	7.480	10.962	4.950	5.115	4.950	5.115	5.115	4.950	5.115	3.803	-		66.055
Forecasted Degree Days														
Central Region	682	591	504	302	130	29	0	5	56	240	391	587		3517
Niagara Region	659	592	490	305	**137**	23	0	3	43	215	365	554		3386
Eastern Region	821	701	592	338	152	38	7	21	109	285	463	716		4243
Forecasted Summer Discretionary Requirement														
PJs	18.301													

Witnesses: J. Denomy
D. Small

STATUS OF TRANSPORTATION CONTRACTS
2014 FISCAL YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Estimated Monthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts expected to be continued in 2014									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	47.628036	$/GJ	-	$/GJ	31-Oct-13
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	49.135970	$/GJ	-	$/GJ	31-Oct-13
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.164530	$/GJ	-	$/GJ	31-Oct-13
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(38,000)	GJ	varies	7.164530	$/GJ	-	$/GJ	31-Oct-13
5	TCPL FT Dawn to EDA		114,000	GJ	varies	13.284330	$/GJ	-	$/GJ	31-Oct-13
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	12.769190	$/GJ	-	$/GJ	31-Mar-14
7	TCPL FT Parkway to CDA		572	GJ	varies	3.786090	$/GJ	-	$/GJ	31-Oct-13
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.948780	$/GJ	-	$/GJ	1-Jan-18
9	TCPL STS Parkway to CDA		283,892	GJ	varies	3.786090	$/GJ	-	$/GJ	31-Oct-13
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	9.755480	$/GJ	-	$/GJ	31-Oct-13
11	TCPL STS Parkway to EDA		9,716	GJ	varies	9.755480	$/GJ	-	$/GJ	31-Oct-13
12	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.240300	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
13	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.240300	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
14	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.160000	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-15
15		US border to Chicago	75.0	mmcf	varies	16.500000	$US/dth	-	$US/dth	31-Oct-15
16	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.014000	$US/dth	-	$US/dth	31-Oct-15
17		Cdn border to Dawn	101,285	GJ	varies	0.570500	$/GJ	-	$/GJ	31-Oct-15
18	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.014000	$US/dth	-	$US/dth	31-Oct-15
19		Cdn border to Dawn	83,349	GJ	varies	0.570500	$/GJ	-	$/GJ	31-Oct-15
20	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies			Negotiated Toll		31-Oct-15
21		Cdn border to Dawn	52,753	GJ	varies			Negotiated Toll		31-Oct-15
22	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies			Negotiated Toll		31-Oct-15
23		Cdn border to Dawn	52,753	GJ	varies			Negotiated Toll		31-Oct-15
24	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.382000	$/GJ	-	$/GJ	31-Mar-14
25	Union Gas Dawn to Parkway		106,000	GJ	varies	2.382000	$/GJ	-	$/GJ	31-Oct-18
26	Union Gas Dawn to Parkway		57,100	GJ	varies	2.382000	$/GJ	-	$/GJ	31-Oct-19
27	Union Gas Dawn to Parkway		18,703	GJ	varies	2.382000	$/GJ	-	$/GJ	31-Oct-14
28	Union Gas Dawn to Parkway		200,000	GJ	varies	2.961000	$/GJ	-	$/GJ	31-Oct-22
29	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.382000	$/GJ	-	$/GJ	31-Oct-14
30	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.011000	$/GJ	-	$/GJ	31-Oct-14
31	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.011000	$/GJ	-	$/GJ	31-Mar-14
32	Union Gas Parkway to Dawn		236,586	GJ	varies	0.579000	$/GJ	-	$/GJ	31-Mar-14

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Estimated Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
	Additional Contracts to meet Peak Day in 2013										
33	Peaking Service - CDA		105,505			varies		varies		1-Dec-12	31-Mar-13
34	Peaking Service - EDA		52,753			varies		varies		1-Dec-12	31-Mar-13
			158,258								
35	TCPL STFT - CDA	Empress to CDA	42,500	GJ	varies	n/a	$/GJ	-	$/GJ	1-Nov-12	31-Mar-13
36	TCPL STFT - CDA	Empress to CDA	195,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Dec-12	28-Feb-13
37	TCPL STFT - CDA	Empress to CDA	65,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Jan-13	31-Mar-13
38	TCPL STFT - EDA	Empress to EDA	60,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Dec-12	28-Feb-13
38	TCPL STFT - EDA	Empress to EDA	30,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Jan-13	31-Mar-13
			392,500								
	Contracts to meet Peak Day in 2014										
39	Peaking Service - CDA	- pending	105,505			varies		varies		1-Dec-13	31-Mar-14
40	Peaking Service - EDA	- pending	52,753			varies		varies		1-Dec-13	31-Mar-14
			158,258								
41	TCPL FT - CDA	Empress to CDA	38,000	GJ	varies	47.62804	$/GJ	-	$/GJ	1-Nov-13	31-Oct-14
42	TCPL FT - CDA	Empress to CDA	50,000	GJ	varies	47.62804	$/GJ	-	$/GJ	10-Sep-13	31-Oct-14
43	TCPL FT - CDA	Empress to CDA - pending	120,000	GJ	varies	47.62804	$/GJ	-	$/GJ	1-Nov-13	31-Oct-14
44	Niagara to CDA		50,000			Negotiated				1-Nov-13	31-Mar-14
45	Niagara to CDA		25,000			Negotiated				1-Nov-13	31-Mar-15
46	Dawn to CDA		50,000			Negotiated				1-Nov-13	31-Mar-14
47	Dawn to CDA		25,000			Negotiated				1-Nov-13	31-Mar-15
48	TCPL FT - EDA	Empress to EDA	50,000	GJ	varies	49.13597	$/GJ	-	$/GJ	1-Nov-13	31-Mar-15
49	TCPL FT - EDA	Empress to EDA	96,250	GJ	varies	49.13597	$/GJ	-	$/GJ	1-Nov-13	31-Oct-15
50	TCPL FT - EDA	Empress to Iroquois - pending	26,956	GJ	varies	49.45575	$/GJ	-	$/GJ	1-Nov-13	31-Oct-16
			531,206								

STATUS OF TRANSPORTATION CONTRACTS
2015 FORECAST YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	EstimatedMonthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts expected to be continued in 2015									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(42,500)	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
5	TCPL FT Dawn to EDA		114,000	GJ	varies	15.52514	$/GJ	0.03229	$/GJ	31-Oct-13
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	14.71519	$/GJ	0.03038	$/GJ	31-Mar-14
7	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-13
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	1-Jan-18
9	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-13
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
11	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
12	Niagara to CDA		200,000	GJ	N/A					
13	TCPL Bram West		800,000	GJ	N/A					
14	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
15	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
16	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.1600	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-15 (1)
17		US border to Chicago	75.0	mmcf	varies	16.5000	$US/dth	-	$US/dth	31-Oct-15
18	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
19		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
20	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
21		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
22	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies		Negotiated Toll			31-Oct-13 (2)
23		Cdn border to Dawn	52,753	GJ	varies		Negotiated Toll			31-Oct-13 (2)
24	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies		Negotiated Toll			31-Oct-15 (2)
25		Cdn border to Dawn	52,753	GJ	varies		Negotiated Toll			31-Oct-15 (2)
26	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14 (3)
27	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
28	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
29	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
30	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	31-Oct-22
31	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
32	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
33	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
34	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) the Alliance contract will not be renewed beyond the October 31, 2015 expiry date
(2) these Vector contracts will not be renewed beyond the October 31, 2015 expiry date
(3) the Company is planning to contract for an incremental 400,000 Gj/day of M12 capacity effective November 1, 2015

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Estimated Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
	Pending Contracts to meet Peak Day in 2015										
35	Peaking Service - CDA		105,505	GJ		varies		varies		1-Dec-14	31-Mar-15
36	Peaking Service - EDA		52,753	GJ		varies		varies		1-Dec-14	31-Mar-15
			158,258								
37	TCPL STFT - CDA	Empress to CDA	42,500	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Nov-14	31-Mar-15
38	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Dec-14	27-Feb-15
39	TCPL STFT - CDA	Empress to CDA	140,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Jan-15	28-Feb-15
40	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Jan-15	31-Mar-15
41	TCPL FT - EDA	Empress to EDA	175,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Nov-13	31-Oct-15
			557,500								

STATUS OF TRANSPORTATION CONTRACTS
2016 FORECAST YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	EstimatedMonthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts expected to be continued in 2016									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	0	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
5	TCPL FT Dawn to EDA		114,000	GJ	varies	15.52514	$/GJ	0.03229	$/GJ	31-Oct-13
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	14.71519	$/GJ	0.03038	$/GJ	31-Mar-14
7	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-13
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	1-Jan-18
9	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-13
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
11	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
12	Niagara to CDA		200,000	GJ	N/A					
13	TCPL Bram West		800,000	GJ	N/A					
14	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
15	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
16	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
17		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
18	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
19		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
20	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14
21	Union Gas Dawn to Parkway		400,000		varies	2.3820	$/GJ	-	$/GJ	(1)
22	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
23	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
24	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	1-Nov-19
25	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	2-Nov-19
26	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	1-Nov-19
27	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
28	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
29	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) the Company is planning to contract for an incremental 400,000 Gj/day of M12 capacity effective November 1, 2015

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Demand Charge		Commodity Charge		Effective Date	Expiry Date
	Pending Contracts to meet Peak Day in 2015										
30	Peaking Service - CDA		0	GJ		varies		varies		1-Dec-15	31-Mar-16
31	Peaking Service - EDA		52,753	GJ		varies		varies		1-Dec-15	31-Mar-16
			52,753								
32	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Jan-16	31-Mar-16
33	TCPL FT - EDA	Empress to EDA	150,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Nov-15	n/a
			250,000								

OVERVIEW – 2014 – 2016 OPERATING AND MAINTENANCE COSTS

1. The purpose of this evidence is to provide an overview of Enbridge Gas Distribution Inc.'s ("Enbridge" or the "Company") Operating and Maintenance ("O&M") forecast expenses for three years from 2014 to 2016 within the Company's Customized Incentive Regulation ("IR") Application. The Company's forecast of O&M expenses within the Allowed Revenue amounts for 2014 to 2015 is $425.3 million in 2014, $428.5 million in 2015, and $439.5 million in 2016. This Overview explains the main components of the 2014 to 2016 O&M Budget referred to as the P&M Budget", including embedded productivity savings, and sets out how the three year O&M Budget was created. Details of the components of the O&M Budget are found in the balance of the D1 series of exhibits.

2. The O&M Budget presented in this evidence is the result of a recent budget process. That process began with the preparation of "Bottom-Up" budgets, by O&M departments across the Company (collectively, the "Other O&M"). Those budgets were to be combined with O&M budgets in areas like DSM, Customer Care, pensions and RCAM, where the related costs are forecast using approaches that have previously been reviewed by the Ontario Energy Board ("OEB", or the "Board").

3. When those proposed O&M budgets were collected and combined, and then reviewed by Enbridge's Executive Management Team (the "EMT"), it was determined that the proposed increases in Other O&M were too high. Direction was provided to limit budget increases to a level at or near inflation, and to accomplish this in part by finding ways to manage the business without increasing

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R. Lei
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the size of the workforce (effectively freezing the number of Full Time Equivalent ("FTE") positions. Given growth in work requirements across the Company, the expectation is that limiting O&M budget increases to around the level of inflation will require the Company to find and take advantage of productivity initiatives over the 2014 to 2016 period.

4. Throughout the budget process, the Company has taken steps to ensure a reasonable and modest rate impact resulting from the O&M growth, while taking into account the Company's key business objectives of a continued focus on safety and reliability, customer service, and compliance with legislative and regulatory requirements. The final 2014 to 2016 O&M Budget represents an outcome that incorporates expected productivity savings and allows the Company to safely operate and maintain the distribution system and meet its obligations to customers.

5. This Overview evidence sets out the main components of the 2014 to 2016 O&M Budget, including the process used to arrive at that budget, under the following topics:

   A. Explanation of the components of Enbridge's forecast O&M expenditures over the period of 2014 to 2016,

   B. Description of the budgeting process that identified the O&M budget, including explanation of the main drivers of the cost changes in the O&M budget,

   C. Explanation of how the Company incorporated productivity in the proposed O&M Budget for 2014 to 2016,

D. Explanation of year over year variances in the 2014 to 2016 O&M Budget, and

E. Evaluation of the Reasonableness of Enbridge's Overall O&M Budget for 2014 to 2016.

A. O&M Budget Components

6. The Company's total O&M Budget is grouped into five categories: Customer Care/CIS Service Charges ("CC/CIS"), Demand Side Management ("DSM"), Pension and OPEB Costs, Regulatory Cost Allocation Methodology ("RCAM"), and Other O&M. This grouping is consistent with the approach that has previously been presented to the Board.

7. A summary of the overall O&M Budget from 2013 Board Approved to 2016 Budget, sorted by these five categories, is provided in Table1.

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2013 Board Approved to 2016 Budget

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.	Categories ($ Millions)	Board Approved 2013	Budget 2014	Budget 2015	Budget 2016	2014 vs. 2013	2015 vs. 2014	2016 vs. 2015
1.	Customer Care/CIS Service Charges	$89.4	$92.6	$96.5	$100.4	$3.2	$3.9	$3.9
2.	Demand Side Management ("DSM") (1)	31.6	32.2	32.8	33.5	0.6	0.6	0.7
3.	Pension and OPEB Costs	42.8	37.2	33.8	30.9	(5.6)	(3.5)	(2.9)
4.	Regulatory Cost Allocation Methodology("RCAM")	32.1	35.3	34.0	33.8	3.2	(1.3)	(0.2)
5.	Other O&M	219.2	228.0	231.5	241.0	8.8	3.5	9.5
6.	Total Net Utility O&M Expense	$415.1	$425.3	$428.5	$439.5	$10.2	$3.2	$11.0

(1) 2013 DSM reflects the final Board approved amount of $31.6M

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8. The first four categories of O&M budgets set out above are determined through the application of mechanisms or approaches that have previously been presented to and accepted by the OEB. Each of these are described below:

   a. *Customer Care/CIS*: As a result of the EB-2011-0226 proceeding, the Board approved a mechanism to establish Enbridge's Customer Care O&M Costs and Customer Information System ("CIS") costs for each year from 2013 to 2018. This mechanism is detailed in the EB-2011-0226 Enbridge Gas Distribution Customer Care and Customer Information Settlement Agreement (the "CC Settlement"). Essentially, it sets a per customer cost for Customer Care and CIS services, which is applied to an updated customer forecast each year (using the definition of customer numbers in the Accenture contract) to determine the revenue requirement associated with those services. The CC Settlement does not address the determination of the Company's Bad Debt expense in each of these years. As contemplated in the CC Settlement, the Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA") was established to facilitate a rate smoothing mechanism agreed to in order to defer some of the impact of completing the recovery of the CIS capital and related costs on rates in 2013 into future years. Please refer to Exhibit D1, Tab 10, Schedule 1 for a review of the treatment of CC/CIS costs as a result of the CC Settlement.

   b. *RCAM (Regulatory Cost Allocation Methodology)*: The RCAM amount for 2014 to 2016 utilizes the RCAM methodology which was approved by the

Board in EB-2006-0034. Under the RCAM methodology, the Company completes an annual review of the services it requires and receives from its corporate parent Enbridge Inc. The service schedules which govern the services received are amended as required. RCAM results are the subject of an annual review by interveners through the RCAM consultative. Although the RCAM costs for 2013 were part of the overall Board-approved Other O&M amount of $251.3 million, Enbridge has removed the RCAM forecast costs of $32.1 million from that figure, in order to present RCAM separately within its 2014 to 2016 O&M Budget. The details of RCAM expenses for 2013 to 2016 are explained in evidence at Exhibit D1, Tab 4, Schedule 1.

c. *Pension and OPEB (Other Post-Employment Benefit) Costs*: Through the EB-2011-0354 proceeding, Enbridge and other parties agreed that the Company should recover only its actual pension and OPEB costs over the coming IR term. As a result of the Settlement Agreement for EB-2011-0354, a new variance account, the Post-Retirement True-up Variance Account (the "PTUVA") was created to true-up both pension and OPEB costs in 2013, so that variances from forecast amounts would be recovered from or credited to ratepayers. The Company is proposing the continuation of this approach, including the use of the PTUVA for the 2014 through 2018 years within this Customized IR Application. The PTUVA evidence is provided at Exhibit D1, Tab 8, Schedule 1. For the 2014 to 2018 period, the forecast pension expense included within the O&M Budget was derived from Mercer Report - Updated Estimated 2014 to 2018 Accrual Costs as of March 28, 2013 (Exhibit D1, Tab 16, Schedule 1

Appendix 1), and the forecast OPEB expense included within the O&M

Budget was derived from a Mercer report, dated April 1, 2013 (Exhibit D1, Tab 16, Schedule 1, Appendix 2).

d. *DSM (Demand Side Management)*: The DSM budget has a separate regulatory process for application and approval of costs. The 2014 DSM budget is based on the recently filed DSM Plan updated for the 2013 and 2014 rate years in EB-2012-0394. The 2014 DSM budget will be approved by the Board in this proceeding. The 2015 and 2016 DSM budgets have been escalated by inflation of 2.0% each year. The DSM evidence can be found at Exhibit D1, Tab 7, Schedule 1.

9. The balance of the Company's O&M Budget is categorized as "Other O&M". This category consists of HR related costs (net of capitalization) including salaries and wages, employee benefits, short term incentive program, employee training and development, materials and supplies, outside services, consulting, repairs and maintenance, fleet, rents and leases, telecommunications, travel and other business expenses, memberships, provision for uncollectables, claims, damages, legal fees, audit fees, A&G capitalization, and other.

10. As the O&M budgets related to CC/CIS, pension and OPEB costs, DSM, and RCAM are determined in accordance with the Board approved approaches and methodologies set out above, and are described in their respective D1 exhibits, the primary focus of this O&M Overview evidence is on the Other O&M Budget.

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11. Table 2, below, provides a standard detailed schedule of the proposed Other O&M Budgets for 2014 to 2016 by cost type, as compared to the 2013 Board approved Capital Budget amount of $219.2 Million. The listing of Other O&M by department is provided in Table 10, at the end of this exhibit.

Table 2
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Board Approved to 2016 Budget

Line No.	Particulars ($ millions)	Board Approved 2013 (a)	Budget 2014 (b)	Budget 2015 (c)	Budget 2016 (d)	2014 vs. 2013 (b)-(a)	2015 vs. 2014 (c)-(b)	2016 vs. 2015 (d)-(c)
1.	Salaries and Wages	$167.7	$170.6	$174.6	$179.0	$2.9	$4.0	$4.4
2.	Benefits	25.3	25.8	26.4	26.9	0.5	0.6	0.6
3.	Short Term Incentive Program	20.7	21.2	21.6	22.1	0.5	0.5	0.5
4.	Employee Training and Development	4.8	5.0	4.8	4.8	0.2	(0.2)	0.0
5.	Materials and Supplies	5.3	5.2	5.2	5.3	(0.1)	0.1	0.1
6.	Outside Services	83.7	86.1	85.7	91.2	2.4	(0.4)	5.5
7.	Consulting	5.1	4.7	4.9	5.2	(0.4)	0.1	0.3
8.	Repairs and Maintenance	2.3	2.4	2.4	2.4	0.0	0.0	0.0
9.	Fleet	10.2	10.4	10.5	10.7	0.1	0.2	0.2
10.	Rents and Leases	7.3	7.4	7.5	7.8	0.0	0.1	0.3
11.	Telecommunications	3.6	3.7	3.8	3.9	0.1	0.1	0.1
12.	Travel and Other Business Expenses	5.4	5.0	5.1	5.1	(0.3)	0.0	0.0
13.	Memberships	5.0	5.0	5.1	5.2	0.0	0.1	0.1
14.	Claims, Damages and Legal Fees	0.9	0.9	1.0	1.0	0.1	0.0	0.0
15.	Interest on Security Deposits	0.8	1.3	2.0	2.5	0.5	0.7	0.5
16.	Provision for Uncollectibles	9.5	9.5	9.5	9.5	-	-	-
17.	Legal Fees	2.7	2.8	2.8	2.9	0.1	0.1	0.1
18.	Audit Fees	1.6	1.6	1.6	1.7	0.0	0.0	0.0
19.	Other	4.5	4.6	4.9	5.0	0.1	0.3	0.1
20.	Internal Allocations and Recoveries	(29.9)	(29.5)	(29.6)	(30.1)	0.4	(0.1)	(0.6)
21.	Capitalization (A&G)	(37.8)	(35.5)	(36.4)	(37.1)	2.3	(0.9)	(0.7)
22.	Capitalization	(75.5)	(76.8)	(78.7)	(80.7)	(1.4)	(1.9)	(1.9)
23.	Regulatory Eliminations	(4.0)	(3.3)	(3.2)	(3.3)	0.8	0.1	(0.1)
24.	Other O&M	$219.2	$228.0	$231.5	$241.0	$8.8	$3.5	$9.5

Witnesses: S. Kancharla
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B. O&M Budget Process, including Main Drivers of the Cost Changes

12. In early March 2013, the Company made the decision to proceed with this Customized IR plan, which includes forecasts of 2014 to 2016 costs to inform the building up of Allowed Revenue amounts. At that time, the Company initiated a process to create its O&M Budget for 2014 to 2016, to support the Customized IR Application.

13. The O&M budgeting process began with a request to individual O&M departments to create three-year budgets setting out their spending requirements, while trying to limit budget increases to the level of inflation. Shortly thereafter, the Budget Letter which sets out economic assumptions and general guidelines was issued to departments to develop their "Bottom-Up" (or "grass-roots") budget. The Budget Letter indicated an expectation that overall budget increases for each department will be at or less than the applicable inflation rate, and that each department would be asked to find cost saving and efficiencies.

14. In response to this direction, individual O&M budgets were prepared. These budgets represented the costs that each department reasonably expected will be experienced over the 2014 to 2016 term. Before each budget was finalized, it was reviewed and endorsed by the relevant leadership within each group.

15. The individual budgets were then provided to the Finance Department to be combined together into an overall O&M Budget for 2014 to 2016. That activity was completed by early April 2013, and the results were presented to the EMT for review and approval.

16. The O&M Budget that was presented to the EMT contained cost increases significantly higher than applicable inflation levels. Notwithstanding the concerns raised by representatives of the various operating groups within the Company that these budgets were reasonable and necessary, the EMT made the decision that overall Other O&M Budget increases had to be reduced to a level consistent with expected inflation levels. As noted, the O&M budgets for the other categories of spend identified on Table 1 were set using pre-established methodologies; they were therefore not subject to update.

17. The decision to revisit and reduce the Other O&M Budget was made in light of several factors, including the following:

    a. A desire to limit rate increases attributable to O&M cost increases, keeping in mind the significant extraordinary capital spending required for the GTA and Ottawa Reinforcement projects and the Work and Asset Management System ("WAMS") project; and

    b. A recognition that cost savings should be found in coming years, by identifying and benefitting from productivity and efficiency initiatives. These cost savings are expected to provide "headroom" to accommodate the increasing O&M demands and requirements of the business.

18. In mid-April 2013, instruction was provided to representatives of the O&M departments to create updated versions of their budgets, with cost increases limited to inflation.

19. To ensure that the second budget submission met this expectation, the following approach was adopted:

    a. An inflation rate of approximately 2% was applied for 2014 to 2016 to all O&M departments;

    b. An assumption was made that salaries, wages and benefits costs would grow at this inflation rate, notwithstanding that these very significant costs would increase faster (for example, benefits are actually increasing at 6.1% per annum and merit increases are forecasted at 3.0% per annum).

    c. A decision was made to add no new FTEs from 2014 to 2016.

    d. Several discrete cost items that could not be accommodated within inflationary increases would be included separately within the budget. For example,

        i. IT incorporated $4.1 million for new WAMS hosting and support costs in 2016 over and above the business as usual inflationary increase.
        ii. Interest on Security Deposits will increase in line with expectations of interest rate hikes.

    e. Bad debt expense will be kept flat at the 2012 level of $9.5 million for 2014 to 2016. This was expected to partly fund some of the increases described above.

20. The updated Other O&M Budget, prepared in response to the direction above, was completed by May 2013, and was subsequently approved by the EMT.

21. Table 3, below, sets out the O&M Budget reduction from the initial first iteration to the final second iteration:

Table 3
Enbridge Gas Distribution
2014-2016 O&M Budget Changes

Line No.	Categories ($ Millions)	Col. 1 1st Iteration Initial Budget 2014	Col. 2 Budget Cuts	Col. 3 2nd Iteration Final Budget 2014	Col. 4 1st Iteration Initial Budget 2015	Col. 5 Budget Cuts	Col. 6 2nd Iteration Final Budget 2015	Col. 7 1st Iteration Initial Budget 2016	Col. 8 Budget Cuts	Col. 9 2nd Iteration Final Budget 2016
1.	CC/CIS Service Charges	$92.6		$92.6	$96.5		$96.5	$100.4		$100.4
2.	RCAM	35.3		35.3	34.0		34.0	33.8		33.8
3.	DSM	32.2		32.2	32.8		32.8	33.5		33.5
4.	Pension and OPEB Costs	37.2		37.2	33.8		33.8	30.9		30.9
5.	Other O&M	247.6	(19.6)	228.0	257.4	(25.9)	231.5	270.5	(29.5)	241.0
6.	Total Net Utility O&M Expense	$444.9	($19.6)	$425.3	$454.4	($25.9)	$428.5	$469.0	($29.5)	$439.5

22. The cost drivers which influence the individual O&M budgets which underpin the overall O&M Budget are set out within the evidence for each of those budgets, found in the balance of the D1 series of exhibits.

23. On an overall basis, though, the main cost drivers that are expected to influence the Other O&M Budget include the following:

a. Continuation of core business activities, as in the past, accounts for the largest part of the Other O&M Budget.

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b. Continued customer growth, of more than 35,000 new customers each year, along with rising customer service demands from existing customers, adds to O&M demands and requirements.

c. Heightened compliance and worker safety requirements and expectations will continue to lead to increasing costs.

d. Increasing focus on System Integrity and Reliability requirements, along with the inherent demands from an aging infrastructure, also contribute to rising O&M costs.

24. In advancing this Other O&M Budget, which limits cost increases to a level at or near inflation, the Company recognizes that it is taking on real risks in terms of being able to operate at that cost level. That is seen by the fact that the "grass-roots" budgets that were prepared within the Company requested significantly more. It is also seen in the fact that there are known items whose costs will exceed the rate of increase set out within the Other O&M Budget. Examples include the following:

a. Expected higher salary and wage increase requirements of around 3% per year.

b. Expected increases in benefits costs – these costs are expected to increase 6.1% annually in 2014 and onwards.

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c. Expected increases in work requirements resulting from a growing customer base. For example, the service work associated with adding new customers will drive an incremental cost of approximately $2 million each year, which is not covered by the inflation escalation.

d. Expected increases in work requirements resulting from increased requirements for safety and integrity work.

e. Expected increases in Outside Services costs, as external contractors for the Operations Department are expected to increase their rates by between 3% and 6% during the IR period.

f. Costs that will result from compliance with new legislation and regulations (e.g. Bill 8, which is expected to drive higher costs as requests for locates will increase substantially).

g. Risk of increases to bad debt expense, which has been forecast to stay flat through the IR term. Bad debt expense is sensitive to several significant, non-controllable, external factors such as gas prices, weather, and economy. In the event of higher gas prices and/or colder weather and/or weakening economy, bad debt expense would be expected to increase significantly.

C. <u>Incorporation of Productivity in the O&M Budget</u>

25. As explained above, the Other O&M Budget for 2014 to 2016 is set at a level that will be very challenging to achieve. By taking this approach, the Company

recognizes that it will only be able to operate within the Other O&M Budget by being able to find productivity and efficiency gains.

26. To accomplish this, there are a number of productivity initiatives embedded within the Other O&M Budget.

27. First, and most significant, is the decision to add no new incremental FTEs from 2014 to 2016. The FTE budget for 2014 to 2016 is expected to decrease slightly year over year. The FTEs presented in Table 4, below, represent the Company's total gross FTEs before capitalization.

Table 4
Enbridge Gas Distribution
Full Time Equivalents (FTE's)
From 2013 Estimate to 2016 Budget

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.	Salary Bands	Estimate 2013	Budget 2014	Budget 2015	Budget 2016	2016 vs. 2015	2015 vs. 2014	2014 vs. 2013
1.	Management	157	154	153	152	(1)	(1)	(3)
2.	Supervisory	1,492	1,484	1,472	1,470	(1)	(12)	(8)
3.	Union	739	739	739	739	-	-	(0)
4.	Total FTE	2,388	2,377	2,364	2,361	(2)	(13)	(11)

28. The decision to not add any incremental FTEs means that all employees will have to be more productive in order to accommodate increasing work requirements with the same staffing levels. By continuing to focus on prioritizing and streamlining

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their work, O&M departments are anticipated to accomplish significant productivity gains during the three years. Maintaining the existing FTE levels will partially relieve the cost pressure in the HR related costs: salaries and wages, employee benefits, STIP, IT, and facility costs. Should it be determined that additional FTEs are required this will have to be funded by savings elsewhere within O&M costs.

29. Examples of individual productivity initiatives within the Company's O&M departments are set out in the evidence for each department. One such example is seen in efforts to reduce locate and damages costs. Locate volumes have been rising over time due to improved excavator awareness and enhanced enforcement activities from the TSSA. Further increases are expected as a result of the passage of Bill 8 (Ontario Underground Infrastructure Notification System Act). However, incremental cost increases are expected to be partially offset by savings driven by fewer damages to the Company's pipeline system and greater workforce efficiency. Further details are set out at Exhibit D1, Tab 17, Schedule 1.

30. Above and beyond the productivity gains previously identified above, and within the individual evidence for the O&M departments, Enbridge will need to find further significant productivity savings in order to operate within the cost levels indicated in the Other O&M Budget. As noted, the Other O&M Budget contains conservative assumptions that are unlikely to materialize, such as limiting wage and benefit costs increases to 2%, assuming no increase in bad debt costs, and assuming no incremental requirements for new customers. To accommodate likely additional cost increases in those areas, the Company is committed to pursuing further productivity initiatives to maintain its O&M costs at modest inflationary levels without sacrificing safety, compliance, and customer service.

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D. Year over Year Variance Explanations

31. The 2014 to 2016 O&M Budget is set out at Tables 1 and 2 above. Set out below are high-level explanations of the year-to-year changes in the Other O&M Budget.

32. Discussion of the year-to-year changes in the level of the O&M Budgets for DSM, Customer Care/CIS, RCAM and Pension/OPEBs can be found in the specific evidence addressing each of those items.

2014 Budget Comparison to 2013 Board Approved – Other O&M

33. The 2013 Board Approved "All other O&M" amount of $251.3 million is an envelope amount which combines both RCAM and Other O&M by department, and is not specifically allocated to any particular O&M expense. Subsequently, the Company allocated $32.1 million to RCAM (because that was the cost forecast within the 2013 rates proceeding) and the remaining Other O&M amount of $219.2 million was allocated to departments as shown in Table 10. As a result, the $219.2 million Other O&M amount within the 2013 Budget is compared to 2014 Budget in the category of Other O&M.

34. The 2014 Other O&M is budgeted at $228.0 million. This is an increase of $8.8 million or 4.0% over the 2013 Board Approved. Exclusive of effectiveness of staff adds in 2013 ($3.3 million), increase for Ontario hearing costs ($0.7 million), increase for interest on security deposits ($0.5 million), the increase at the departmental baseline level represents $4.3 million or 2.0%, which is consistent with the inflation rate. The variances by major drivers between the two years are

summarized on Table 5. The variances by cost type within the O&M Budget for these years can be seen in Table 2.

Table 5
Enbridge Gas Distribution
Other O&M Year over Year Analysis
2014 Budget vs. 2013 Board Approved

	$ million			
2013 Budget	**$219.2**			
Major Drivers for Change				Rationale for changes
1. Salary and wage increases (net)	1.5			Salary increase at inflation net of capitalization
2. HR related costs: Benefits, STIP and training	1.2			The increases are driven by salary increase
3. External contractors rate increase	0.8			The contractors used by Operations to conduct maintenance work
4. Locates, ILI, and leak and corrosion	0.3			The increased work for safety compliance
5. Other inflationary pressures	0.5			
		4.3	2.0%	
6. Effectiveness of staff adds in 2013	3.3			2013 staff adds become fully effective in 2014 and onwards
7. Ontario hearing costs	0.7			Greater complexity, time, and cost required for 2nd Gen IR proceeding
8. Interest on security deposits	0.5			Higher forecasted interest rates for 2014
		4.5	2.1%	
9. Total increase		8.8	4.0%	
2014 Budget	**$228.0**			

2015 Budget Comparison to 2014 Budget – Other O&M

35. The 2015 Other O&M Budget is $231.5 million. This is an increase of $3.5 million or 1.5% over the 2014 Budget. Exclusive of the increase for interest on security deposits ($0.7 million) and the decrease for Ontario hearing costs (-$2.0 million), the departmental O&M will go up by $4.8 million or 2.1% over 2014, which is in line with the inflation rate. The variances by principal drivers between the two years are summarized on Table 6. The variances by cost type within the O&M Budget for these years can be seen in Table 2.

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Table 6
Enbridge Gas Distribution
Other O&M Year over Year Analysis
2015 Budget vs. 2014 Budget

	$ million			
2014 Budget		**$228.0**		
Major Drivers for Change				Rationale for changes
1. Salary and wage increases (net)	2.1			Salary increase at inflation net of capitalization
2. HR related costs: Benefits, STIP and training	0.9			The increases are driven by salary increase
3. Locates, ILI, and leak and corrosion	0.7			Anticipated higher cost related to safety compliance
4. External contractors rate increase	0.4			The contractors used by Operations to conduct maintenance work
5. IT HW/SW maintenance costs	0.2			Cost increase reflecting market changes and Finance Renewal Project
6. Other inflationary pressure	0.5			
		4.8	2.1%	
7. Interest on security deposits	0.7			Higher forecasted interest rates for 2015
8. Ontario hearing costs	(2.0)			Anticipated reduction in the complexity of the main rate case proceeding
		(1.3)	-0.6%	
9. Total increase		3.5	1.5%	
2015 Budget		**$231.5**		

2016 Budget Comparison to 2015 Budget – Other O&M

36. The 2016 Other O&M Budget is $241.0 million. This is an increase of $9.5 million or 4.1% over the 2015 Budget. Exclusive of new WAMS hosting and support costs ($4.1 million) and the increase for interest on security deposits ($0.5 million), the departmental O&M will increase $4.9 million or 2.1% over 2015, which aligns with the inflation rate. The variances by principal drivers between the two years are summarized on Table 7. The variances by cost type within the O&M Budget for these years can be seen in Table 2.

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Table 7
Enbridge Gas Distribution
Other O&M Year over Year Analysis
2016 Budget vs. 2015 Budget

		$ million		
2015 Budget		**$231.5**		
Major Drivers for Change				Rationale for changes
1. Salary and wage increases (net)	2.4			Salary increase at inflation net of capitalization
2. HR related costs: Benefits, STIP and training	1.1			The increases are driven by salary increase
3. IT HW/SW maintenance costs	0.3			Cost increase reflecting market changes and FRP project
4. External contractors rate increase	0.4			The contractors used by Operations to conduct maintenance work
5. Locates, ILI, and leak and corrosion	0.3			Anticipated higher cost related to safety compliance
6. Other inflationary pressure	0.4			
		4.9	2.1%	
7. WAMS IT hosting and support costs	4.1			New WAMS system is expected to be in service in 2016
8. Interest on security deposits	0.5			Higher forecasted interest rates for 2016
		4.6	2.0%	
9. Total increase		9.5	4.1%	
2016 Budget		**$241.0**		

E. Reasonableness of Enbridge's Overall 2014 to 2016 O&M Budget

37. As explained, the process used to establish Enbridge's O&M Budget for 2014 to 2016 ensures that the resulting budgets limit any increases to a reasonable level, which includes productivity challenges that the Company will have to meet.

38. In order to confirm the reasonableness of the resulting O&M Budget, the Company (with assistance from Concentric Energy Advisors Inc. ("Concentric") examined the O&M Budget from a number of perspectives. All the results indicate that the Company is productive and the O&M Budget for 2014 to 2016 is reasonable.

39. One way that the Company's O&M spending was evaluated was through benchmarking. Enbridge asked Concentric to update the benchmarking study that had been filed in the Company's 2013 rate case. The updated benchmarking study is set out as Appendix A to the Concentric Incentive Ratemaking Report, which is

filed as Exhibit A2, Tab 9, Schedule 1. As noted in the benchmarking discussion, the Company's O&M costs per customer are already among the lowest in the industry. In 2011 the Company had the fifth lowest O&M cost per customer in an industry study group comprised of 28 U.S. natural gas utilities. The Company's forecasted O&M cost per customer for 2014 to 2016 is expected to be higher than recent history, but not by a significant amount. It should be highlighted that Enbridge's forecasted O&M cost per customer of $208 in 2014 is lower than the industry study group average for 2011.

40. The Company conducted an analysis to compare the Company's forecast O&M cost per customer from 2014 to 2016 with the Company's historical trend of O&M costs per customer.

41. Table 8 and Chart 1, below, set out the results of this work, confirming that the Company's total O&M cost per customer will continue to decline (on a constant dollar basis) throughout the 2014 to 2016 IR term.

Table 8
Enbridge Gas Distribution
Total Operation and Maintenance Expense
Cost Per Customer

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2016 Constant Dollars per Customer										
Total Utility O&M Cost Per Customer [1]	$199.5	$189.4	$191.2	$189.5	$189.2	$200.1	$202.3	$199.6	$193.1	$190.5
Nominal Dollars per Customer										
Total Utility O&M Cost Per Customer [1]	$164.4	$161.0	$165.6	$166.8	$170.3	$183.3	$189.4	$190.9	$188.9	$190.5
Number of Customers (000's) [2]	1,825	1,865	1,888	1,926	1,960	1,995	2,025	2,060	2,095	2,132

Notes:
1. Does not include ancillary program costs, or demand side management costs
2. Number of Customers represent total unlock customers

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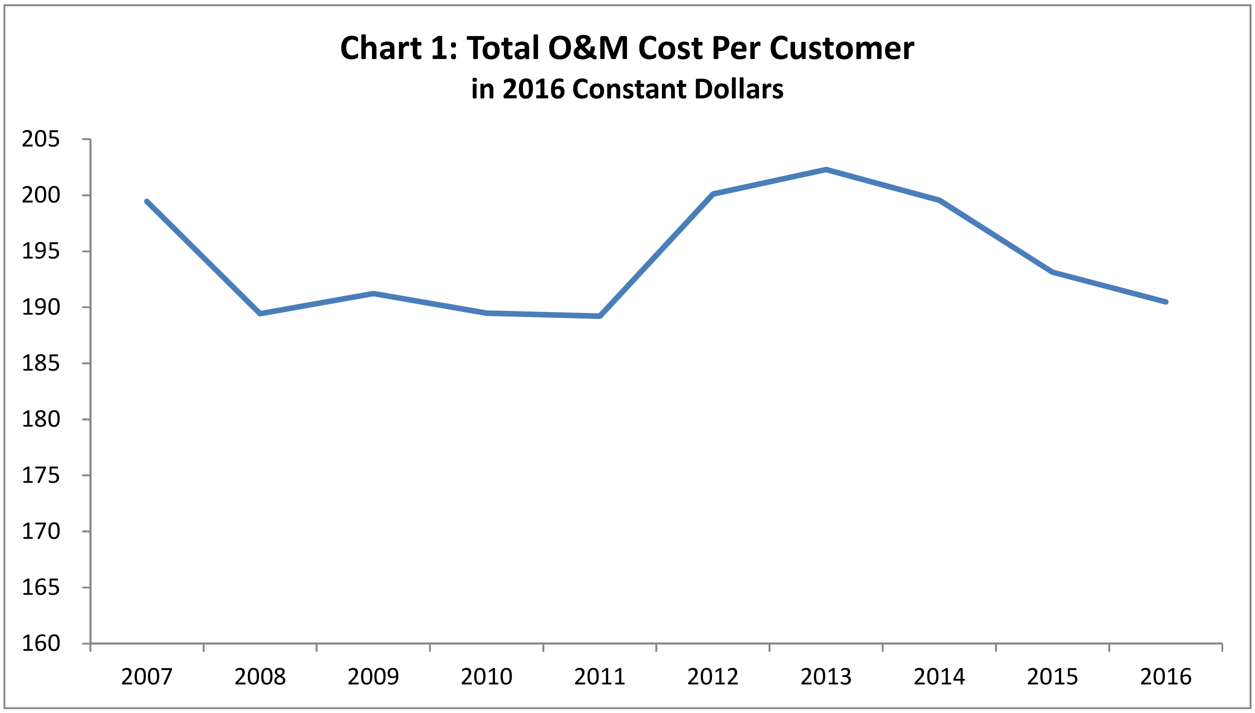

42. Table 9 and Chart 2, below, quantify the Company's cost per customer for "Other O&M" only, over the same time period. Again, this analysis confirms that Company's Other O&M cost per customer will continue to decline (on a constant dollar basis) throughout the 2014 to 2016 IR term.

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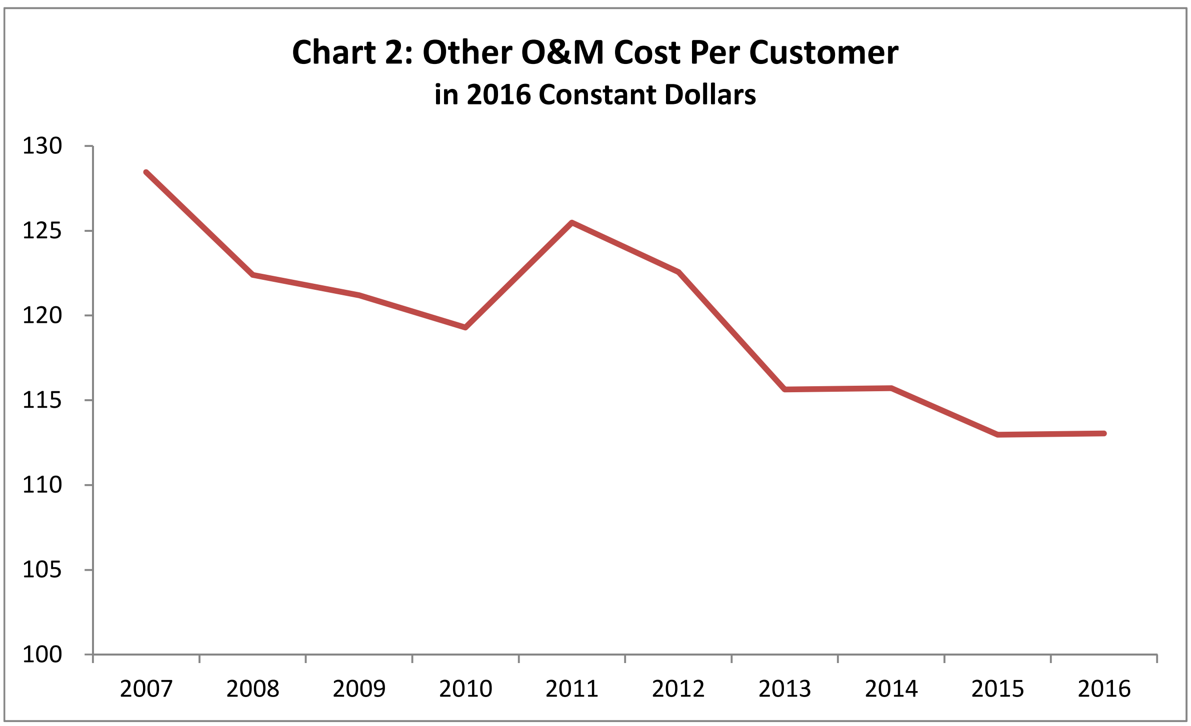
Table 9
Enbridge Gas Distribution
Other Operation and Maintenance Expense
Cost Per Customer

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2016 Constant Dollars per Customer										
Other Utility O&M Cost Per Customer	$128.5	$122.4	$121.2	$119.3	$125.5	$122.6	$115.6	$115.7	$113.0	$113.0
Nominal Dollars per Customer										
Other Utility O&M Cost Per Customer	$105.9	$104.0	$105.0	$105.0	$112.9	$112.3	$108.2	$110.7	$110.5	$113.0
Number of Customers (000's) [1]	1,825	1,865	1,888	1,926	1,960	1,995	2,025	2,060	2,095	2,132

Notes:
1. Number of Customers represents total unlock customers



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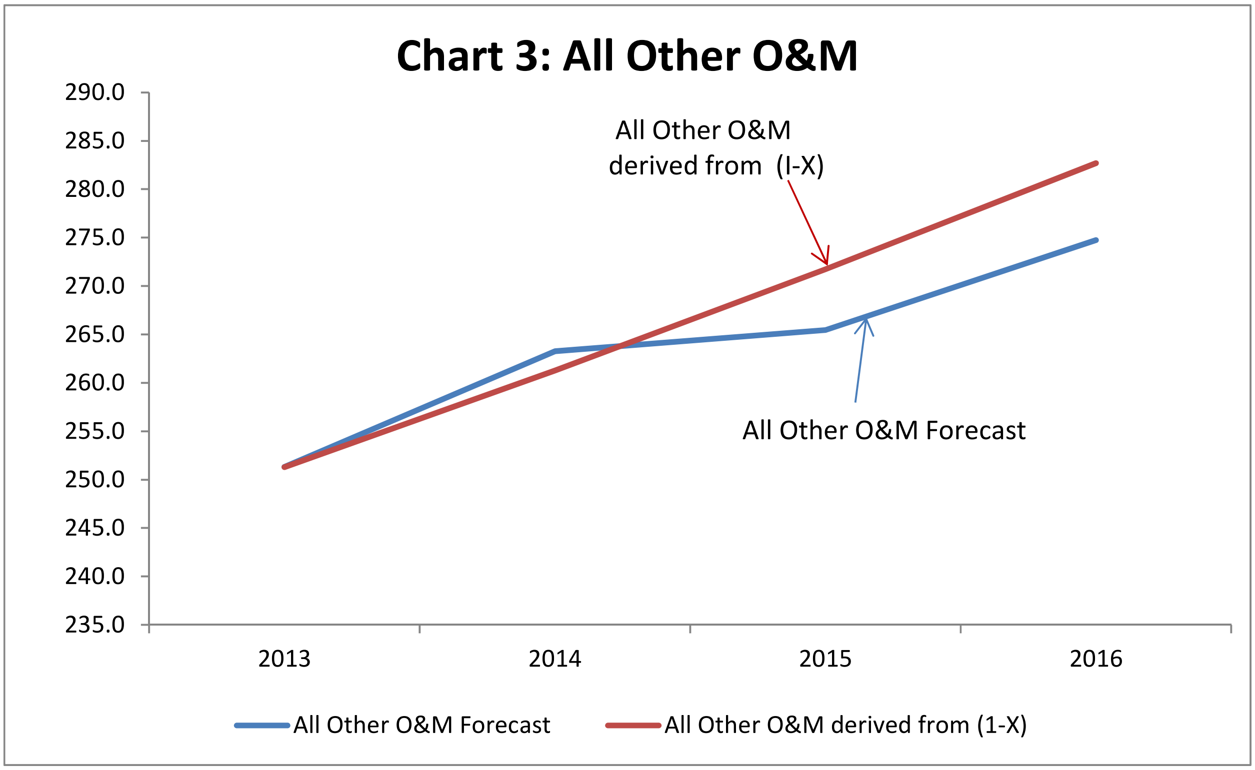
43. The ten year trend set out in the Tables and Charts above indicates that both the Total O&M and Other O&M cost per customer in 2016 constant dollars are on the decline, which demonstrates that the Company not only has achieved productivity gains in the past years but also continues to drive productivity on a cost per customer basis in 2014 and onwards.

44. A third way that the Company's O&M spending was evaluated was through a Partial Factor Productivity ("PFP") study conducted by Concentric. For that analysis, Concentric compared the Company's forecasted All Other O&M cost per customer (including RCAM and Other O&M) over the 2014 to 2016 period with All Other O&M cost per customer that would be expected using the inflation and productivity factors that would be applied to Enbridge's O&M costs within an I-X incentive regulation ratemaking model. As explained in Concentric's report, the conclusion is that All Other O&M cost per customer would be expected to increase by 2.24% under a PFP I-X framework applied to All Other O&M costs. Enbridge's All Other O&M cost per customer is forecast to increase by a lesser amount. A comparison of the Company's forecasted All Other O&M cost per customer and the All Other O&M cost per customer derived from applying the PFP I-X formula is shown in the Chart 3 below. The difference between the expected O&M cost level and Enbridge's actual O&M Budget can be considered to be productivity savings. Concentric's full analysis is set out within the Concentric Incentive Ratemaking Report, which is filed as Exhibit A2, Tab 9, Schedule 1.



45. The conclusion to be taken from the analyses presented above (benchmarking analysis, PFP analysis, O&M cost per customer in 2016 constant dollars) is that the Company's 2014 to 2016 O&M Budget is at a reasonable level that incorporates productivity.

F. <u>Conclusion</u>

46. This O&M Budget Overview exhibit has explained the Company's approach, reasoning and decisions that led to the 2014 to 2016 O&M Budget. The

determination to limit O&M Budget increases to a level consistent with inflation, even at a time of growing cost pressures, indicates that the Company is dedicated to cost effective operation during an extraordinary period of capital spending pressures. The inclusion of productivity savings within the O&M Budget enables and confirms this approach.

47. The balance of the D1 series of exhibits set out the details of Enbridge's 2014 to 2016 O&M Budget, organized by categories of spending (departments). Table 10 below shows the O&M budgets by department, and provides exhibit cross-references setting out where the full evidence for each individual O&M budget is found.

Table 10
Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2013 Board Approved to 2016 Budget

Line No.	Particulars ($000's)	Evidence Reference	Board Approved 2013 (a)	Budget 2014 (b)	Budget 2015 (c)	Budget 2016 (d)	2014 vs. 2013 (b)-(a)	2015 vs. 2014 (c)-(b)	2016 vs. 2015 (d)-(c)
1.	Operations	D1-13-1	$ 63,894	$ 65,800	$ 67,300	$ 68,800	$ 1,905	$ 1,500	$ 1,500
2.	Pipeline Integrity & Engineering	D1-17-1	38,158	39,004	39,874	40,775	846	870	900
3.	Human Resources and Facilities	D1-16-1	21,460	21,972	22,462	22,970	512	490	508
4.	Employee Benefits	D1-16-1	25,261	25,756	26,350	26,925	495	594	575
5.	Short Term Incentive Program	D1-16-1	20,700	21,156	21,628	22,116	456	472	488
6.	Information Technology	D1-14-1	25,846	26,387	26,976	31,680	541	589	4,704
7.	Regulatory, Public and Government Affairs	D1-18-1	22,107	22,589	20,914	21,251	482	(1,675)	336
8.	Finance	D1-11-1	11,453	11,717	11,979	12,249	264	262	270
9.	Provision for Uncollectibles (Bad Debts)	D1-3-1	9,500	9,500	9,500	9,500	-	-	-
10.	Customer Care (Exclude CC/CIS and Bad Debts)	D1-15-1	2,447	2,334	2,399	2,449	(113)	66	50
11.	Business Development & Customer Strategy (excluding DSM)	D1-15-1	6,493	6,185	6,363	6,506	(308)	177	144
12.	Legal and Corporate Security	D1-12-1	5,161	5,253	5,370	5,491	92	117	121
13.	Energy Supply and Policy	D1-19-1	4,228	4,243	4,348	4,449	16	105	101
14.	Non-Departmental	D1-20-1	3,554	3,589	3,669	3,752	34	80	83
15.	Capitalization (A&G)		(37,795)	(35,500)	(36,440)	(37,140)	2,295	(940)	(700)
16.	Interest on Security Deposit		780	1,313	2,019	2,521	533	706	501
17.	Regulatory Eliminations		(4,049)	(3,276)	(3,192)	(3,295)	773	84	(103)
18.	Other O&M		219,197	228,022	231,520	240,999	8,825	3,498	9,479
19.	Customer Care/CIS Service Charges	D1-10-1	89,444	92,631	96,502	100,426	3,187	3,870	3,925
20.	Pensions and OPEB Costs	D1-16-1	42,800	37,248	33,764	30,887	(5,552)	(3,484)	(2,877)
20.	Corporate Cost Allocations (including direct costs)	D1-4-1	45,761	44,977	45,140	45,874	(784)	164	733
21.	Demand Side Management Programs (DSM)	D1-7-1	31,588	32,159	32,802	33,458	571	643	656
22.	Conservation Services	D1-15-1	2,728	1,976	-	-	(752)	(1,976)	-
23.	Subtotal		431,519	437,013	439,728	451,644	5,494	2,715	11,916
	Other Regulatory Eliminations								
24.	To eliminate Corporate Cost Allocations above RCAM	D1-21-1	(13,666)	(9,695)	(11,179)	(12,116)	3,971	(1,484)	(937)
25.	To eliminate Conservation Services and Overheads	D1-21-1	(2,728)	(1,976)	-	-	752	1,976	-
26.	Total Eliminations		(16,394)	(11,671)	(11,179)	(12,116)	4,723	492	(937)
27.	Total Net Utility O&M Expense		$415,125	$425,342	$428,549	$439,528	$10,217	$3,207	$10,979

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.
3) 2013 Capitalization (A&G) includes the effectivness of staff adds in 2013 of $3.3 million

Witnesses: S. Kancharla
R. Lei
A. Mandyam
M. Torriano

EMPLOYEE EXPENSES AND WORKFORCE DEMOGRAPHICS

1. The purpose of this evidence is to outline Enbridge Gas Distribution Inc.'s ("Enbridge" or the "Company") employee-related expenses over the 2014 to 2016 term. These costs are not only unavoidable, they are necessary to ensure the continued provision of services at the levels expected and demanded by Enbridge's customers.

2. One issue that the Canadian market has been experiencing over the last number of years is an aging workforce. The Company has an aging working population preparing for retirement at a time when there are fewer skilled workers available to take their place. The risks of skill and resource gaps are significant. At Enbridge currently 23% of the workforce is over the age of 55, and 13% of the employees are eligible to retire. By 2016, 21% of the workforce will be eligible to retire, and by 2021, 32% of the workforce could retire. Considering the potential impacts to the workforce due to retirements, significant efforts are being placed on creating plans to ensure the Company replace critical skills and knowledge in order to maintain and operate a safe, reliable and cost effective gas distribution system. It is critically important that Enbridge is able to attract the best candidates for employment opportunities which will reflect on the services that are provided to customers.

3. Enbridge is not the only employer that faces such challenges. It must compete for talent with other companies and industries that similarly must look for skilled workers in an aging workforce. Therefore the Company needs to structure its total compensation programs, including pensions and benefits, to attract and retain the necessary skills. This must also provide for employee development that retain skilled and engaged workforce.

Compensation

4. Enbridge utilizes a cash compensation package that consists of a fixed component (base salary and wages) plus a variable pay component Short-Term Incentive Program ("STIP"). The STIP budget is included in the Human Resources Department O&M Expenses, Exhibit D1-16-1. In addition, senior positions within the utility are eligible for a Long Term Incentive Program ("LTIP") to ensure focus on achievement of long-term Company goals and to incent retention. The budget for LTIP is one component of Enbridge Inc. charges.

5. Compensation levels are competitively based upon market conditions that reflect the local labour market in which the Company competes for talent. Enbridge has a defined comparator group of companies comprised of oil, gas, and utility companies and other large Canadian organizations with whom we compete for talent and in which compensation surveys are conducted annually. The pay philosophy that the Company utilizes is to target total cash compensation at the 50th percentile of the market. Enbridge ensures that compensation for employees is consistent with its pay philosophy and is competitive and appropriate.

6. The Company will continue to evaluate its compensation practices on an ongoing basis to ensure labour market competitiveness and the retention of critical skills.

7. Base salary budgets are established annually with consideration given to external compensation consultant's forecasts of salary increases, negotiated wage settlements and consumer price index projections.

8. For 2013, the Company has or will provide the following salary increases:

Non-union Employees	Unionized Employees
April 1, 2013 – 2.8%	January 1, 2013 – 2%
	July 1, 2013 – 1%

9. For 2014 to 2016, the Company's salary and wages will include anticipated increases for employees that are consistent with market conditions at the time, partially offset by vacancies and hiring lags. These costs will be accommodated within the overall O&M budget.

10. The variable pay component (STIP) is an element of compensation for all permanent employees. It is performance-driven and is intended to focus employees on achieving and exceeding specific corporate, business unit, departmental and individual goals that are determined on an annual basis. Company achievements of financial and operational results are tracked through the use of "scorecards" at the Business Unit level. These measures provide a direct line of sight for employees. They can clearly understand their contributions to the business and the role they play in the achievement of business results. The business unit component of the STIP incentive pay program is tied to achievements of the scorecard results.

11. Including measurable and clear metrics to the Company scorecard aligns the business objectives of the Company with the activities of the employee. Employees as a result understand their contribution to the business and the role that they play in the achievement of business results. Many metrics are dependent upon improved productivity and performance. Examples of such metrics are;

(1) Safety, (2) Customer Satisfaction, (3) Financial Performance, (4) Pipeline Integrity.

12. For each of the scorecard metrics, a minimum performance threshold is established. If actual performance is below the minimum threshold established for a specific metric, there is no payout for that element of the incentive opportunity. In addition, for all non-union employees, there is a minimum threshold of individual performance that must be achieved to be eligible to receive an incentive payout.

13. Executive and senior leadership positions have an LTIP component included within their standard compensation. This is a stock-based plan comprised of three types of awards – Incentive Stock Options ("ISO's"), Performance Stock Units ("PSU's"), and Restricted Share Units ("RSU's"). ISO grants vest equally over four years of continuous employment. PSU's are subject to vesting, but only after a specified performance goal has been achieved. RSU's vest at the end of a three-year period provided continuous employment is maintained. Eligibility is based on salary grade. Senior executives are eligible for ISO's and PSU's. Directors are eligible for ISO's and RSU's and senior managers are eligible for RSU's.

14. Participation in the LTIP plan is determined by the Human Resources Compensation Committee of the Enbridge Inc. Board of Directors and is restricted to those positions seen to be key from a decision-making and operational accountability perspective. Individual performance ratings and succession criticality are factored into the grant calculation.

15. In addition, other select managers can be nominated for a discretionary RSU grant. Consideration is given to those individuals who are identified as critical to retain due

to specialized skills or for succession purposes. Nominations must be approved by the Human Resources Compensation Committee of the Enbridge Inc. Board of Directors.

Benefits and Pension

16. An important element in being able to attract and retain the talent that Enbridge requires is the ability to offer market-competitive pension and benefit plans.

17. Enbridge provides a total compensation package including pension and benefit plans that are competitive within the Company's market comparator group. Enbridge ensures effective cost management of these plans through intelligent design, efficient utilization, and performance monitoring of the Company's 3rd party service providers.

18. Benefit costs continue to rise. These increases are due to several factors; (1) Canada Pension Plan, Employment Insurance, and Employers Health Tax increases; (2) increased utilization of the benefit plans and the need for increased services given the aging workforce; and (3) higher prescription costs and dental fees. While these costs are expected to increase at approximately 6% per year, the Company has budgeted to manage these cost impacts to inflation rates. This will likely require productivity savings within other areas of the O&M Budget.

19. Enbridge provides a flexible benefit plan for all employees (both union and non-union). Employees receive an annual amount of "flex credits" that can be applied to purchase a customized list of benefits that best suit their needs. Rather than offering a "one size fits all" suite of benefits that may not be fully utilized by each employee, a flex program ensures that benefit coverage is directed at those

elements that will be most utilized and most valued, according to individual need and circumstance.

20. Design features within the plan include cost-containment elements intended to moderate cost escalations. Employee co-payments, fee caps, reimbursement maximums and least-cost-alternative drug coverage are some of the features embedded into the design that provides cost-management support.

21. Enbridge has two retiree benefit plans, based on eligibility. Both are funded by the Company. The plans offer either a traditional benefit plan based on reimbursement for prescription costs incurred, or a health spending account. Both plans have a maximum payout, dispensing fee caps, and lifetime maximums.

22. Enbridge offers two pension plan options – Defined Benefit (“DB”) and Defined Contribution (“DC”) plans within the Enbridge registered pension plan.

23. Costs to provide employees with retirement planning and pension education sessions to address the Company’s fiduciary responsibility to ensure their ability to make informed pension choices are also included within the pension expense category.

Employee Development

24. A fundamental component in effectively managing the transition to replace retiring workers is the need to support their training and development. Ensuring a smooth transition without incurring major skill gaps require technical and business training and an investment in leadership development.

25. The Company has always had a strong focus on providing developmental opportunities to support skills development and enhancement. This is a critical element in being able to attract and retain the talent that the Company needs to maintain the business and provide service to the customers.

26. Enbridge continues to focus on delivering quality developmental programs in a cost-effective manner. The Company continues to make improvements in course development and administration focusing on providing employees with leadership development programs, general skills curriculum, tuition aid, and mentoring programs. This year, a comprehensive, results-based leadership development framework including programs, processes and tools is being implemented. The project will define leadership at Enbridge, assess current competency of the Company's leaders, create development opportunities and work to enhance leadership capability in the organization.

Employee Expenses

27. Below is a Table setting out Enbridge's forecast of employee-related expenses over the 2013 to 2016 term. In the following paragraphs, detail is provided about each element of the expenses.

Table 1

Major Employee Expenses
2013 Budget, 2014 Budget, 2015 Budget, 2016 Budget

Line No.	Particulars ($ 000's)	2013 Budget	2014 Budget	2015 Budget	2016 Budget
		$	$	$	$
1	Salaries and Wages	183,846	188,678	192,304	196,943
2	Short Term Incentive Pay	20,700	21,156	21,628	22,116
3	Benefits	25,261	25,756	26,350	26,925
4	Pension & OPEB	42,800	37,248	33,764	30,887
5	Training and Development	2,502	2,541	2,595	2,650
6	Awards and Allowances	1,435	1,465	1,496	1,529
7	Relocation	500	500	500	500
8	Severances	2,000	2,000	2,000	2,000
9	FTEs	2,388	2,377	2,364	2,361

28. The salaries and wages line in this Table represent both O&M and Capital labour for union and non-union employees. Individual department FTEs and related salaries and wages can be found in the respective O&M department's evidence. FTE's are planned to remain constant over 2014 through 2016 as a greater focus has been placed upon productivity.

29. During the 2014 to 2016 term, Enbridge has budgeted to manage its overall salary cost increases to the forecast projected rate of inflation. The forecast rate of inflation is around 2.2% from 2014 to 2016.

30. The STIP line includes STIP for all permanent employees across Enbridge Gas Distribution, as outlined in Human Resources Department O&M Expenses, Exhibit D1-16-1. The underlying calculation for STIP is percentage of salaries, based on a combination of company performance and individual performance where target performance is assumed on all company and individual metrics.

31. The Benefits line includes employer deductions such as, Canadian Pension Plan, Employment Insurance and Employers Health Tax, as well as flexible credits granted to employees for the purchase of benefit coverage. In addition, the cost of medical and dental claims submitted by retired employees is included. Year over year budget variances are outlined in Human Resources Department O&M Expenses, Exhibit D1-16-1.

32. The Pension and OPEB line includes all contributions to fund the Company pension plans and its post-employment benefits. Pension and OPEB costs for 2014, as provided by Mercer and set out in Reports attached as Appendices to Exhibit D1, Tab 16, Schedule 1, decrease by $5.6 million from the 2013 Budget due to expected returns on higher pension plan asset balances. While forecast amounts have been included for 2015 and 2016, these amounts will be updated within the rate adjustment proceedings for those years. In addition, these amounts are subject to annual true-up through the PTUVA.

33. The Training and Development line includes programs that are applicable for all Enbridge Gas Distribution employees. Additional details related to this are found in the Human Resources Department O&M Expenses, Exhibit D1-16-1. The remainder of the training and development budget is located in each individual department's O&M evidence.

34. The Awards and Allowances are for recognition of employee's milestone years of service, as well as significant employee contribution outside of their normal work activities.

35. The Relocation line is for expenses associated with the relocation of employees. Relocation expenses are a result of succession planning in order to gain the required talent in the specific locations required. These costs are budgeted to remain constant from 2013 through to 2016, even though historically relocation expenses have been significantly higher. Relocation expenses are included in Human Resources Department O&M Expenses, Exhibit D1-16-1.

36. The Severances line includes costs associated with all employee terminations (O&M and capital). A strong focus continues to be placed upon performance management, ensuring employees performance is linked to objectives and desired outcome to drive efficiencies and productivity. As such, $2.0 million has been established for severances in the 2014 through 2016 budget, which allows for severances. The severance expenses are included in the Human Resources Department O&M Expenses, Exhibit D1-16-1.

37. The FTE budget for 2014 to 2016 is expected to decrease slightly year over year as a result of attrition. As the Company is committed to delivering productivity over the course of the IR term, the Company plans to add no new incremental FTEs to keep the overall levels relatively stable for 2014 to 2016. As such, productivity was implicitly embedded in the budget in terms of avoided costs.

REGULATORY COST ALLOCATION METHODOLOGY

Introduction

1. The purpose of this evidence is to update the Board with respect to developments since the 2013 rates case and the Company's plans for the future with respect to the Regulatory Cost Allocation Methodology ("RCAM"). More specifically, this evidence:

   - updates the Board on the Company's plans with respect to the annual RCAM review process as contemplated under the Inter-corporate Services Agreement ("ISA") with Enbridge Inc. dated January 1, 2011;

   - informs the Board of the status of the Company's implementation of the process improvement recommendations made by MNP LLP ("MNP"), the independent evaluator, in its 2013 RCAM Report dated May 17, 2012, filed at Exhibit D2, Tab 1, in the EB-2011-0354 proceeding (the "MNP 2013 Report");

   - outlines for the Board the Company's proposal with respect to the continuation of the corporate cost allocation consultative (the "Consultative") for 2013 and the next incentive regulation period;

   - provides an update with respect to the RCAM generated by the various services and direct charges in 2013; and

   - provides the rationale and support for the 2014-2016 RCAM budgets and references supporting evidence and materials.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

Annual RCAM Review Process

2. The Company has an agreement in place with respect to the renewal of its ISA with Enbridge Inc. for a further period of five years commencing January 1, 2011.[1] As noted by the Company in the EB-2011-0354 proceeding, the RCAM methodology, as approved by the Board, has been consistently applied throughout the first generation incentive rate regulation period starting in 2008. Annual RCAM allocations have been approved by the Company under the RCAM, and the updated RCAM results have been used for the purposes of determining the earnings sharing mechanism.

3. Following MNP's completion of its updated independent review, it generated the MNP 2013 Report which concluded that the RCAM methodology continues to meet all regulatory requirements and remains appropriate for the Company. MNP further concluded that the RCAM methodology was adhered to in the development of allocations for 2012 (and 2013 through the inflation escalator used to develop the 2013 figure used in rates). MNP also reviewed the ISA, which had earlier been reviewed by members of the RCAM Consultative, for the purposes of its renewal and execution in January 2011. MNP found the January 2011 ISA to be consistent with the requirements of the RCAM methodology and the *Affiliate Relationships Code.* Attached to this evidence, as Attachment 3, is a copy of the ISA and Schedule 1 to the ISA, being the RCAM Methodology (Revised January 2011), and Appendix A to Schedule 1, being the RCAM Allocator Definitions (Revised January 2011).

[1] The renewed ISA, dated January 1, 2011, has been executed and a complete copy of the ISA and its schedules is provided in Attachment 3.

4. Given MNP's updated findings and the Board's acceptance of the Complete Settlement of Issue D5, "Is the corporate cost allocation ("RCAM") appropriate?" in EB-2011-0354, the Company reiterates that while it may be appropriate to consider refinements to the RCAM methodology over time, the Company does not believe that fundamental changes to the RCAM methodology are either warranted or appropriate at this time.

5. Therefore, the Company will continue to apply the Board-approved RCAM methodology and will continue to be guided by the same framework, as set out in the main agreement and Schedule 1 to the ISA. Furthermore, as part of the annual review process, as contemplated under Section 5 of Schedule 1 to the ISA (the detailed RCAM methodology document), the Company will continue to examine Enbridge Inc.'s cost inputs, organizational structure and service delivery changes, and alterations to the operating environment. The Company's continued rigorous oversight, as required under the ISA, will ensure that the three-pronged test continues to be satisfied. An overview of the internal process followed at Enbridge is provided in Attachment 2 to this evidence. Where necessary, adjustments will be made to ensure consistency with the spirit and intent of the Board-approved RCAM methodology.

<u>MNP's 2013 Recommendations</u>

6. In the MNP 2013 Report, MNP made several recommendations which it believed might lead to some process improvement. More specifically, MNP suggested the following:

   (a) Categorize and Roll up Services for Comparison Purposes – MNP recommended that the Company categorize and roll up services to levels more consistent with reporting of other utilities for comparison purposes, and subsequently undertake a more structured benchmarking study to evaluate costs.

(b) Business Case Upgrades – MNP recommended that the Company develop two specific upgrades to business cases:

(i) Criteria for External Estimates of Cost – develop and implement more defined exemption criteria for Service Recipients when estimating costs for external provision of services.

(ii) Variance Analysis – add a section to each business case to track year over year variances in allocation cost.

(c) Service Level Evaluation – MNP recommended enhancements to the performance management process. In support, MNP cited leading practices in the area of procurement and vendor management which suggest that the service recipient hold the service provider to agreed-upon performance metrics using a service level agreement or other evaluation mechanism.

(d) Recovery Mechanism – In certain cases where there is a large windfall or shortfall, MNP recommended employing existing or new mechanisms to recover, or otherwise true-up, any material discrepancies based on unanticipated differences between budgeted and actual allocations for the budget year.

7. The Company agrees with the recommendations made by MNP in respect to upgrades to the business cases and has commenced implementation of this recommendation to be effective for the 2013 annual RCAM review process. By

making these changes, it is believed that the process will become more transparent and more descriptive.

8. While the Company agrees directionally with the spirit and intent of MNP's recommendation in respect of the roll up of services into fewer but more encompassing services, the Company notes that this recommendation would likely reduce the granularity of the process and requires further consideration and consultation. In respect of the recommendation regarding service level evaluations, the Company has concerns about the degree of complexity and the time that would be required to enhance the evaluation process. The Company currently has confidence in its review of the services rendered and questions the efficacy and cost of this recommendation. In respect of recommendation (d), Enbridge is not proposing an amendment of this nature to the RCAM methodology.

9. The Company's decision to not proceed with recommendations (a), (c) and (d) follows the dialogue it had with MNP in respect of these recommendations subsequent to MNP providing the MNP 2013 Report. The Company generally determined that the costs of proceeding with these recommendations would likely exceed the anticipated benefits. While it is to be anticipated that services may, over time, be amended, consolidated and/or expanded due to the natural evolution of the business, the Company does not believe that an extensive and time consuming consolidation of the current services is warranted.

Corporate Cost Allocation Consultative

10. While the Company is not obliged to continue the RCAM Consultative pursuant to the RCAM Supplementary Settlement Agreement of September 27, 2007 agreed

to in the EB-2006-0034 proceeding, the Company believes that there is merit in continuing the RCAM Consultative beyond 2012 and is proposing to do so on a go forward basis.

11. The Company is prepared to continue to share relevant information with members of the RCAM Consultative on a confidential and without prejudice basis. This includes updated RCAM financial results and other significant developments or changes associated with the RCAM. As a result, members of the RCAM Consultative will remain informed of any material changes that occur during the term of the next IR period.

2013 RCAM Amount Update

12. At the time of the Company's filing for the 2013 Test Year, MNP had not completed its independent review of the 2012 RCAM. Once MNP provided the MNP 2013 Report, the Company updated its filing adopting MNP's recommendations for 2012 which also impacted the RCAM forecasts for 2013. More specifically, the Board-approved RCAM methodology generated a RCAM for 2012 of approximately $31.8 million. The MNP 2013 Report recommended a reduction of approximately $200,000 to $31.6 million. For the purposes of 2013, the Company inflated the 2012 RCAM of $31.8 million based upon the Alberta consensus CPI forecasts from four banks. This generated a forecast RCAM for 2013 of $32.3 million. This figure was then similarly adjusted downwards pursuant to the MNP recommendation by approximately $200,000. The 2013 rates application was then updated to request a budget of $32.1 million for 2013.

13. Subsequent to the 2013 Rates proceeding, (EB-2011-0354), with the availability of the 2013 budget, an actual RCAM was generated for 2013 using the Board-

approved RCAM methodology. This methodology has been used consistently by the Company and had recently been the subject of a further detailed review by MNP (the 2013 MNP Report). The Company proposes to use this amount, $35.6 million, as the base for the term of the next IR. As part of the annual review process, the Company will ensure that the three-pronged test continues to be satisfied. Through the internal process followed by the Company, the amount allocated to one of the services for 2013 is currently under review and may change. Any change could impact this and possibly other services, as well as the aggregate amount. As such, the figures for 2013 are, to this extent, preliminary and they do not represent the final RCAM amount approved by the Company under the ISA.

14. The net increase from the amount included in the 2013 rates application ($32.1 million) to the actual 2013 RCAM using the Board-approved RCAM methodology amount is $3.5 million. This increase is generally driven by a combination of the increases in the cost base to provide the services and increases in the level of activities undertaken for the Company, including:

<u>Primary Services</u>

(a) an increase in activities and costs in respect of compensation-related matters which were considered and addressed resulting in changes in compensation practices and policies, and increased reporting and research requirements ($0.6 million);

(b) the post-implementation costs associated with the HR Core Project (HR business process enhancements with HR IT system overhaul), including the upgrades to the Enbridge Learning Management System (e-LMS) necessary to support the enhanced employee development programs such as the Accelerated Leadership Development program ($0.6 million);

(c) an increase in Cash Management & Banking Service costs ($0.5 million) resulting from the extensive service provided to the Company in respect of the issuance of commercial paper, execution of spot foreign exchange transactions, settlements of interest payments on the Company's Medium Term Note borrowings with external parties, establishment of credit facilities, and compliance related to these facilities;

(d) activities designed to enhance governance resulting in cost increases in Planning, Management & Execution of Internal Audits Service ($0.4 million) and Records and Information Management Service ($0.3 million); and

(e) increased costs arising from the restructuring of the Company's insurance policy ($0.3 million) that ultimately resulted in a significant reduction in the Company's allocation of insurance premiums as noted below;

General Expenses and Direct Charges

(f) higher stock-based compensation charges resulting from the increase in the number of participants and changes to prevailing stock prices ($2.9 million) and an increase in directors' fees primarily driven by the change in stock prices ($0.4 million); and

(g) as noted earlier, the above increases are offset by a significantly lower insurance premium that resulted from the restructuring of the insurance program implemented through the Insurance Claims Support Strategy and Management Service (-$2.8 million).

15. The details of the allocations to the various services and direct charges for 2013 are identified in Attachment 3.

<u>2014 – 2016 RCAM Budgets</u>

16. For the purposes of developing its forecast RCAM budgets for the years 2014 – 2016, the Company believes that the following trends will have a tendency to reduce annual increases and indeed may lead to annual decreases, for several reasons.

(a) First, with the growth of the Enbridge Inc. enterprises, the Company's percentage share of several of the RCAM allocation factors is likely to decline. This will result in a smaller percentage of Enbridge Inc.'s enterprise costs being allocated to the Company during the subject years. An example of this is the forecast for the General Expense & Direct Charge in relation to directors' fees and expenses. This charge is determined based on the FCER allocator and is forecast to see a decline of approximately 22 percent in 2014, 18 percent in 2015 and 10 percent in 2016, partially due to the above mentioned driver.

(b) Second, the Company is forecasting that the material decrease in insurance premiums that were realized in 2013 will continue in subsequent years.

(c) Third, it is anticipated that there will be little or reduced overall growth in the level of some services over the subject years (notably the Cash Management & Banking service).

17. These general trends lead to a forecast for the 2014 – 2016 budgets of the following:

Table 1

($millions)	2014	2015	2016
Primary Services	19.5	18.0	18.0
General Expenses & Direct Charges	15.4	15.6	15.4
Rate of Return on Invested Capital	0.4	0.4	0.4
Total	$35.3	$34.0	$33.8

18. Table 2 below shows the percentage year-over year changes in Primary Services and General Expenses & Direct Charges for the years 2014 through 2016 based upon the actual 2013 RCAM of $35.6 million.

Table 2

%	2013/4	2014/5	2015/6
Primary Services	-1.3	-8.1	0.1
General Expenses & Direct Charges	-0.6	1.8	-1.4
Overall	-0.9%	-3.7%	-0.6%

A summary Table setting out the costs allocated to the Company for each Primary Service, General Expenses & Direct Charge for each of the years 2009 to 2016 and their corresponding year-over year percentage changes are provided in Attachment 1.

19. While the Company is forecasting that the overall RCAM amount will remain relatively flat or decline during the years 2014 – 2016, it is anticipated that the allocations to several of the Primary Services will still see some growth during these years which will tend to moderate the change. Examples of areas where the Company forecasts that there will be a need for greater services are noted below:

(a) There will be an increase in the allocation to the Records and Information Management Service commencing at 2014 to reflect continued process and system upgrades intended to make it easier to find critical business information. This ability to quickly access and utilize records allows the Company to work more efficiently and safely in its delivery of energy to its customers; and

(b) There will an increase in activities and costs associated with the Finance Renewal Project streamlining many of the intensive and manual processes and replacing poorly integrated and aging technology in financial reporting systems (both of which are required to meet compliance reporting requirements and to enhance value-added decision support capabilities). These additional costs will be allocated to the Khalix and Oracle services.

20. In respect of General Expenses & Direct Charges, it is anticipated that the following will see increases:

(a) Beginning in 2014, there will be higher depreciation costs associated with the capital investment made in the IT Security Project. This increase is identified in the Risk Management System Depreciation line item. The Company recently implemented new security technologies to safeguard the Company's data from unauthorized access and to ensure its availability, confidentiality and integrity by operating secure, controlled and reliable IT systems, networks and applications; and

(b) Stock-based compensation is forecast to be modestly higher in 2015, but the subject of a decline in 2016.

Recent Development

21. On June 11, 2013, Enbridge Inc. announced the formation of Midcoast Energy Partners LP, a master limited partnership to be listed on the New York Stock Exchange with an expected closing and effective date of later this year or early 2014. This master limited partnership will hold U.S. based natural gas transportation assets. This transaction, subsequent to the closing, could have an impact on some of the RCAM allocators. This in turn could have an impact on some of the 2014-2016 figures.

Conclusion

22. The RCAM methodology which was approved by the Board and which the Company has now used over a number of years remains the most appropriate means of determining the amounts that should be reflected in rates to reflect the significant services and benefits that the Company receives from Enbridge Inc. In its simplest terms, the RCAM methodology's adoption of the three prong test helps

ensure that the cost of the services and benefits received from Enbridge Inc., are less than the costs which the Company would have incurred on a stand-alone basis. The significant reduction in insurance premiums negotiated by Enbridge Inc., undoubtedly a reflection to a material extent of the bargaining position of the size of the Enbridge Inc. enterprise, is a notable example.

23. As has been seen in recent years, the declining trend of the Company's percentage share of several of the allocators is continuing and this is one of the drivers of the forecast leveling and decline in RCAM budgets for the years 2014-2016. This leveling of the budgets over the coming years is also a reflection of the rigourous attention paid by the service recipients to their need for the services which are provided by Enbridge Inc.

Enbridge RCAM Allocation Trend - 2009 To 2016

	Services / Direct Charges	2009 (As Approved by Enbridge under the ISA)	2010 (As Approved by Enbridge under the ISA)	2011 (As Approved by Enbridge under the ISA)	2012 (As Approved by Enbridge under the ISA & adjusted by MNP's recommendation)	2013 (Forecast Filed in EB-2011-0354)	2013 (Preliminary - Calculated Using the Board-approved RCAM methodology)	2014 (Forecast Filed in EB-2012-0459)	2013/2014 YOY Change	2015 (Forecast Filed in EB-2012-0459)	2014/2015 YOY Change	2016 (Forecast Filed in EB-2012-0459)	2015/2016 YOY Change
Primary Services	Audit & Accounting Advice	$ 123,457	$ 176,276	$ 202,937	$ 91,270	$ 93,278	$ 158,418	$ 155,250	-2.0%	$ 139,725	-10.0%	$ 136,930	-2.0%
	Board of Directors Support	$ 524,382	$ 653,787	$ 512,237	$ 769,368	$ 785,892	$ 848,267	$ 831,302	-2.0%	$ 748,171	-10.0%	$ 733,208	-2.0%
	Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -		$ -	
	Business Development	$ 442,656	$ 440,041	$ 533,671	$ 736,918	$ 753,039	$ 751,127	$ 736,104	-2.0%	$ 662,494	-10.0%	$ 649,244	-2.0%
	Capital Market Financing & Access	$ 680,419	$ 857,868	$ 986,346	$ 991,870	$ 1,013,640	$ 1,029,508	$ 1,008,918	-2.0%	$ 908,026	-10.0%	$ 889,866	-2.0%
	Cash Management & Banking	$ 268,955	$ 346,810	$ 388,868	$ 481,073	$ 491,656	$ 997,480	$ 748,110	-25.0%	$ 673,299	-10.0%	$ 659,833	-2.0%
	Consolidation and Planning System Technical Support (Khalix)	$ 424,221	$ 492,550	$ 606,411	$ 245,089	$ 249,486	$ 275,164	$ 325,384	18.3%	$ 411,115	26.3%	$ 528,893	28.6%
	Corporate Compliance	$ 103,385	$ 129,802	$ 134,323	$ 197,202	$ 201,540	$ 290,362	$ 284,555	-2.0%	$ 256,099	-10.0%	$ 250,977	-2.0%
	Industry Relations and Corporate Social Responsibility (CSR)	$ 310,317	$ 399,487	$ 465,205	$ 384,365	$ 392,741	$ 415,918	$ 407,600	-2.0%	$ 366,840	-10.0%	$ 359,503	-2.0%
	Emerging Energy Technology Research	$ 55,901	$ 74,371	$ 47,593	$ -	$ -	$ -	$ -		$ -		$ -	
	Employee Development	$ 547,313	$ 803,140	$ 1,200,754	$ 1,245,623	$ 1,273,025	$ 1,318,597	$ 1,292,225	-2.0%	$ 1,163,003	-10.0%	$ 1,139,743	-2.0%
	Enterprise IT Program Management	$ 183,664	$ 413,230	$ 389,669	$ 868,494	$ 887,579	$ 661,348	$ 648,121	-2.0%	$ 583,309	-10.0%	$ 571,643	-2.0%
	Enterprise IT Strategy Planning & Management	$ 446,745	$ 594,422	$ 467,282	$ 624,115	$ 637,845	$ 236,125	$ 231,403	-2.0%	$ 208,262	-10.0%	$ 204,097	-2.0%
	Expense System Management & Technical Support (Oracle iExpense)	$ 147,714	$ 167,015	$ 239,394	$ 95,490	$ 97,384	$ 240,347	$ 290,567	20.9%	$ 378,039	30.1%	$ 496,478	31.3%
	External Audit Coordination	$ 56,582	$ 76,248	$ 63,299	$ 103,399	$ 105,673	$ 207,076	$ 202,934	-2.0%	$ 182,641	-10.0%	$ 178,988	-2.0%
	Financial and Project Accounting System Technical Support (Oracle)	$ 256,641	$ 254,570	$ 261,570	$ 352,161	$ 358,097	$ 517,170	$ 567,390	9.7%	$ 641,021	13.0%	$ 754,200	17.7%
	Gas Supply, Storage, and Transportation Strategy	$ 390,843	$ 231,134	$ -	$ -	$ -	$ -	$ -		$ -		$ -	
	Government Relations	$ 47,715	$ 120,509	$ 34,848	$ 44,917	$ 45,895	$ 48,971	$ 47,992	-2.0%	$ 43,192	-10.0%	$ 42,329	-2.0%
	Human Resources Information Systems (HRIS)	$ 742,447	$ 1,545,942	$ 2,169,992	$ 2,897,597	$ 2,961,312	$ 3,487,053	$ 3,417,312	-2.0%	$ 3,075,581	-10.0%	$ 3,014,069	-2.0%
	Human Resource Advice	$ 168,134	$ 271,938	$ 354,073	$ 201,779	$ 206,184	$ 171,633	$ 168,200	-2.0%	$ 151,380	-10.0%	$ 148,353	-2.0%
	Insurance Claims Support	$ 4,402	$ 6,301	$ 7,145	$ -	$ -	$ -	$ -		$ -		$ -	
	Insurance Strategy and Management	$ 79,418	$ 120,927	$ 119,312	$ 108,240	$ 109,912	$ 325,570	$ 319,059	-2.0%	$ 287,153	-10.0%	$ 281,410	-2.0%
	Investor Services	$ 585,153	$ 685,330	$ 811,451	$ 883,837	$ 903,044	$ 1,099,448	$ 1,077,459	-2.0%	$ 969,713	-10.0%	$ 950,319	-2.0%
	Legal Advice	$ 433,306	$ 749,045	$ 572,710	$ 514,396	$ 525,600	$ 465,382	$ 456,074	-2.0%	$ 410,467	-10.0%	$ 402,258	-2.0%
	Planning, Management & Execution of Internal Audits	$ 187,727	$ 228,607	$ 185,494	$ 191,528	$ 195,741	$ 561,368	$ 550,141	-2.0%	$ 495,127	-10.0%	$ 485,224	-2.0%
	Rate Regulated Entity Support	$ 97,621	$ 128,419	$ 147,295	$ 253,904	$ 259,490	$ 225,727	$ 221,212	-2.0%	$ 199,091	-10.0%	$ 195,109	-2.0%
	Records and Information Management	$ 494,550	$ 298,336	$ 304,392	$ 538,352	$ 550,195	$ 888,504	$ 977,354	10.0%	$ 879,619	-10.0%	$ 862,027	-2.0%
	Risk Assessment and Management	$ 686,348	$ 882,571	$ 1,062,095	$ 878,461	$ 897,681	$ 865,435	$ 848,126	-2.0%	$ 763,313	-10.0%	$ 748,047	-2.0%
	Strategic Planning	$ 160,673	$ 194,768	$ 253,879	$ 327,890	$ 335,020	$ 253,073	$ 248,012	-2.0%	$ 223,210	-10.0%	$ 218,746	-2.0%
	Supply Chain Management	$ 21,249	$ 24,088	$ 30,414	$ 39,706	$ 40,580	$ 46,900	$ 45,962	-2.0%	$ 41,366	-10.0%	$ 40,538	-2.0%
	Tax Reporting & Planning	$ 14,512	$ 21,630	$ 24,894	$ 55,308	$ 56,525	$ 131,679	$ 129,045	-2.0%	$ 116,141	-10.0%	$ 113,818	-2.0%
	Total Compensation and Benefits	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	$ 1,820,969	$ 2,399,292	$ 2,447,278	2.0%	$ 2,202,550	-10.0%	$ 2,158,499	-2.0%
	Employee and Labour Relations	$ 348,384	$ 458,995	$ 552,430	$ 478,201	$ 488,722	$ 588,542	$ 576,771	-2.0%	$ 519,094	-10.0%	$ 508,712	-2.0%
	Portal Suite Operations & Technical Support	$ 236,449	$ 156,062	$ 172,685	$ 330,881	$ 338,160	$ 301,334	$ 295,307	-2.0%	$ 265,777	-10.0%	$ 260,461	-2.0%
	Total Service Charges	**$ 10,121,518**	**$ 13,317,317**	**$ 14,712,914**	**$ 16,713,243**	**$ 17,075,905**	**$ 19,806,817**	**$ 19,555,167**	**-1.3%**	**$ 17,964,817**	**-8.1%**	**$ 17,983,521**	**0.1%**
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (213,789)	$ (1,174,981)	$ (1,150,894)	$ (2,314,784)	$ (2,314,784)	$ (2,129,052)	$ (2,426,795)	14.0%	$ (2,426,795)	0.0%	$ (2,426,795)	0.0%
	Directors Fees & Expenses	$ 426,433	$ 517,905	$ 545,235	$ 744,819	$ 761,205	$ 1,141,370	$ 893,632	-21.7%	$ 734,389	-17.8%	$ 664,398	-9.5%
	Depreciation - Risk Management System	$ 74,436	$ 13,827	$ 68,965	$ 64,951	$ 64,951	$ 133,581	$ 959,418	618.2%	$ 947,223	-1.3%	$ 900,000	-5.0%
	Insurance Premiums	$ 4,571,600	$ 5,179,873	$ 4,338,678	$ 8,483,868	$ 8,483,868	$ 5,652,239	$ 5,786,989	2.4%	$ 5,887,964	1.7%	$ 6,005,723	2.0%
	Audit Fees	$ 1,248,118	$ 1,125,631	$ 1,369,832	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	EGD Stock Based Compensation Charge	$ 4,262,039	$ 4,842,397	$ 6,413,231	$ 7,549,229	$ 7,715,312	$ 10,657,647	$ 10,156,934	-4.7%	$ 10,504,804	3.4%	$ 10,288,631	-2.1%
	Total Direct Charges	**$ 10,368,836**	**$ 10,504,652**	**$ 11,585,047**	**$ 14,528,083**	**$ 14,710,552**	**$ 15,455,785**	**$ 15,370,178**	**-0.6%**	**$ 15,647,585**	**1.8%**	**$ 15,431,957**	**-1.4%**
	Return on Invested Capital	**$ 625,604**	**$ 443,159**	**$ 369,543**	**$ 368,896**	**$ 357,703**	**$ 353,189**	**$ 356,721**	**1.0%**	**$ 349,586**	**-2.0%**	**$ 342,595**	**-2.0%**
	Total Enbridge Allocation	**$ 21,115,958**	**$ 24,265,127**	**$ 26,667,504**	**$ 31,610,223**	**$ 32,144,160**	**$ 35,615,791**	**$ 35,282,065**	**-0.9%**	**$ 33,961,988**	**-3.7%**	**$ 33,758,072**	**-0.6%**

Overview of RCAM Review Process

Step1 – service recipients:

- Refresh the service descriptions
  - confirm existing requirements as stated in the service schedules
  - review any changes to EI's service offerings and add/delete as required
  - note any required changes through the application of the OEB's cost incurrence test
- Refresh the business cases (originally developed in 2006)
  - confirm requirements, indicate necessary exclusions to meet the cost incurrence test
  - make other modifications, provide clarifications and details
  - update the cost for alternative models, showing what the cost would have been if services were acquired externally/in-house

Step 2 – Company' coordinator:

- submit to EI, for pricing, the service schedules that have now been updated with the current year's requirements
- Once EI's pricing information is received, the charges are incorporated into the service schedules/business cases and they are sent back to the service recipients for their final review

Step 3 – service recipients:

- conduct final review of the service schedules/business cases, assessing EI's competitiveness in conjunction with the alternative costs determined by the service recipients in step 1

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

- update the cost/benefit section of the business cases and provide final remarks and conclusion
- provide year-over-year cost variance explanation

Step 4 – service recipients:

- confirm acceptance of EI's charges by signing-off on their service schedules/business cases
- confirm that the OEB's 3-prong regulatory test is satisfied

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

INTERCORPORATE SERVICES AGREEMENT

THIS AGREEMENT made as of the first day of January, 2011

B E T W E E N:

ENBRIDGE INC., a corporation incorporated under the laws of Canada (the "**Service Provider**")

- and -

ENBRIDGE GAS DISTRIBUTION INC., a corporation incorporated under the laws of the Province of Ontario (the "**Service Recipient**")

WHEREAS the above-named parties ("**Parties**") entered into a prior intercorporate services agreement made as of January 1, 2006 (the "**Prior Agreement**");

AND WHEREAS the Affiliate Relationships Code for Gas Utilities rule (the "Code") of the Ontario Energy Board ("**OEB**") prohibits the term of an intercompany services agreement to be greater than five (5) years without OEB approval;

AND WHEREAS the Parties wish to continue the relationship set out in the Prior Agreement whereby the Service Provider provides services to the Service Recipient, in accordance with the terms and conditions of this agreement, and any attached schedules (the "**Agreement**").

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter contained, the Parties agree:

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1. Termination of Prior Agreement

Effective as of 11:59 pm EST on December 31, 2010, the Prior Agreement is terminated. Effective as of 12:00 am EST on January 1, 2011 this Agreement shall be in full force and effect.

2. Regulatory Considerations

The Parties acknowledge that this Agreement shall be subject to any rule or order applicable to the Service Recipient made by the OEB pursuant to the Ontario Energy Board Act, S.O. 1998, c. 15, Sch. B., s. 44, including without limitation, the Code, as amended from time to time. The Service Provider agrees to do such things as are reasonably necessary to assist the Service Recipient in complying with these rules, including without limitation:

(a) to comply promptly with all requests either made or authorized by the OEB for information with respect to:

- (i) the Services; and
- (ii) the cost to the Service Provider of providing the Services; and

(b) to include equivalent provisions to those set out in this section in any contracts the Service Provider enters into with another of its affiliates for the purpose of providing any service, resource or product used in the provision of the Services.

3. Regulatory Cost Allocation Methodology

The Parties have developed a regulatory cost allocation methodology ("**RCAM**"), attached hereto as Schedule 1, that has been reviewed and approved by the OEB and may be amended from time to time. RCAM sets out the purpose, objectives, principles, and procedures underlying the identification and costing of the Services for the purpose of determining the amounts which the Service Recipient will request to be recovered in rates from time to time. Where a section of this Agreement is inconsistent with RCAM, RCAM shall prevail to the extent of the inconsistency.

4. Services and Allocation Bases

The Parties shall develop a schedule to describe each individual Service ("**Service Schedules**"), and the applicable quantity and quality indicators, to be provided in any given year. The Services may be comprised of one or more of the following components, as described in further detail in RCAM:

a) **Primary Services:** defined as a service provided by the Service Provider to the Service Recipient either as the sole provider or as a supplemental provider (where the Service Recipient performs a component of the required activities of the service). A list of the primary services and the bases of allocation attributable thereto, are set out in RCAM.

b) **Support Services:** defined as a service provided by the Service Provider that is necessary to support a primary service to the Service Recipient. Support services are further classified as infrastructural, content, or resource support services, and are listed in RCAM with the applicable allocator.

c) **General Expenses:** defined as a significant cost that benefits the Service Recipient, and requires allocation on a basis separate from a primary service because the driver of the cost is different, or because the cost is a large, third party cost. A list of the general expenses and the basis of allocation attributable thereto, are set out in RCAM.

d) **Direct Charges:** defined as a general expense for services that can be externally priced and specifically attributed to the Service Recipient without loading. A list of the direct charges and the basis of allocation attributable thereto, are set out in RCAM.

e) **Department Costs:** defined as all direct employee and employee-related costs, plus general expenses related to the department, that relate to the primary services and support services.

f) **Return on Invested Capital:** defined as a charge for the Service Recipient's share of the weighted average cost of capital applied to the net book value of property, plant and equipment used to deliver the services. The return on invested capital shall be no higher than the Service Recipient's weighted average cost of capital as approved by the OEB from time to time.

5. Allocation Procedures

Cost allocations shall be made in accordance with the processes and procedures documented in RCAM, which describes how primary services are fully-burdened with department costs, direct charges, general expenses, support services (also fully burdened), and a return on invested capital before being allocated to the Service Provider.

The Service Provider, in consultation with the Service Recipient, shall set the RCAM cost allocations for the Services prior to December 31 each year, or as soon thereafter that the Parties can conclude the relevant budgeting and cost allocation processes, and in any event, prior to March 31 of the year to which the RCAM cost allocations are applicable. The Parties shall execute a confirmation notice ("**RCAM Confirmation Notice**") and Service Schedules to evidence the Parties' agreement to the RCAM cost allocations for that year, which shall be incorporated into and form part of this Agreement. A copy of the pro forma RCAM Confirmation Notice is attached hereto as Schedule 2, and the executed RCAM Confirmation Notice shall become Schedule 2(a) for 2011, Schedule 2(b) for 2012, and so on.

The RCAM cost allocations shall not be amended within the year to which they apply, except in accordance with section 7 below.

In addition to the determination of the RCAM cost allocations, the Service Provider shall develop cost allocations applicable to the Service Recipient pursuant to an alternate corporate cost allocation methodology ("**CAM**") that is not approved by the OEB. The Service Provider shall determine and apply the CAM cost allocations in accordance with the CAM policies and procedures developed by the Service Provider from time to time.

6. Payment Procedures

The following sets forth the procedure applicable to payments related to Services delivered hereunder:

a) The Service Provider shall prepare monthly recurring journal entries to one or more accounts of the Service Recipient based upon the CAM cost allocations and provide an annual CAM report to the Service Recipient at least thirty (30) days prior to the beginning of the calendar year to which the journal entries relate, or as soon thereafter as reasonably practicable, as a payment notice ("**Payment Notice**") to the Service Recipient.

b) The Service Recipient shall notify the Service Provider immediately of any inaccuracy in each Payment Notice, and failing resolution, the Parties shall endeavor to resolve the dispute in accordance with the dispute resolution mechanism set out in section 15 below.

c) The Service Recipient shall pay the amounts indicated in each Payment Notice on or before the end of each calendar quarter to which the Payment Notice relates, or if there is a dispute about the amount, within thirty (30) days of the date that an amount has been determined by the dispute resolution mechanism. The Service Provider shall apply any payments made hereunder to and in satisfaction of both the CAM and RCAM cost allocations owing.

d) All amounts payable under this Agreement are expressed, and shall be paid, in Canadian dollars unless otherwise stated in the Payment Notices.

e) In the event that the Minister of National Revenue for Canada or any other competent authority at any time proposes to issue or does issue any assessment or assessments that impose or would impose any liability for tax of any nature or kind whatsoever on the Service Provider or the Service Recipient on the basis that the fair market value of any of the services is different than the amount charged by the Service Provider for the corresponding Services (the "**Services Charge**"), and in the event that the Parties agree that the fair market value of the services is different than the Services Charge, then upon such agreement the Services Charge that the Service Recipient is obligated to pay for the said services shall be varied by increasing or decreasing the amount of the Services Charge as the Service Recipient and the Service Provider may agree.

7. Service Agreement Review and Amendment Process

This Agreement and any related Service Schedules may be amended from time to time upon the approval in writing of the Parties. Version control and archival storage of all amendments shall be the responsibility of the Service Recipient.

8. Term and Termination

8.1 Subject to section 8.3 below, this Agreement shall be effective January 1, 2011, and terminate December 31, 2015 (the "**Term**").

8.2 Each Service Schedule shall have an initial term of one year commencing January 1, 2011 and be automatically renewed for subsequent periods of one year until the end of the Term, subject to any service adjustments agreed to by the Parties in accordance with this Agreement.

8.3 The Parties may terminate this Agreement by mutual consent, in writing, except that the Service Recipient shall have the right to terminate this Agreement immediately in the event that it ceases to be a direct or indirect wholly owned subsidiary of the Service Provider.

9. Indemnification

Each of the Parties (the "**Indemnifier**") shall indemnify and hold the other Party (the "**Indemnified Party**") harmless from and against any loss, damage, claim, liability, debt, obligation or expense (including reasonable legal fees and disbursements) incurred or suffered by the Indemnified Party caused by the Indemnifier, and relating in any way to this Agreement or the provision of the services, including any loss, damage, claim, liability, debt, obligation or expense resulting from or arising from or in connection with a negligent act or negligent omission of the Indemnifier.

10. Confidential Information and Personal Information

Each of the parties hereto agrees to keep all information provided by the other party (the "**disclosing party**") to it (the "**receiving party**") that the disclosing party designates as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure ("**Confidential Information**") confidential, and a receiving party shall not, without the prior consent of an authorized senior officer of the disclosing party, disclose any part of such Confidential Information which is not available in the public domain from public or published information or sources except:

a) to those of its employees who require access to the Confidential Information in connection with performance of Services hereunder;

b) as in the receiving party's judgement may be appropriate to be disclosed in connection with the provision by the receiving party of Services hereunder;

c) as the receiving party may be required to disclose in connection with the preparation by the receiving party or any of its direct or indirect holding companies, affiliates or subsidiaries of reporting documents including, but not limited to, annual financial statements, annual reports and any filings or disclosure required by statute, regulation or order of a regulatory authority; and

d) to such legal and accounting advisors, valuators and other experts as in the receiving party's judgement may be appropriate or necessary in order to permit the receiving party to rely on the services of such persons in carrying out the receiving party's duties under this Agreement.

The covenants and agreements of the parties relating to Confidential Information shall not apply to any information:

a) which is lawfully in the receiving party's possession or the possession of its professional advisors or its personnel, as the case may be, at the time of disclosure and which was not acquired directly or indirectly from the disclosing party;

b) which is at the time of disclosure in, or after disclosure falls into, the public domain through no fault of the receiving party or its personnel;

c) which, subsequent to disclosure by the disclosing party, is received by the receiving party from a third party who, insofar as is known to the receiving party, is lawfully in possession of such information and not in breach of any contractual, legal or fiduciary obligation to the disclosing party and who has not required the receiving party to refrain from disclosing such information to others; or

d) disclosure of which the receiving party reasonably deems necessary to comply with any legal or regulatory obligation which the receiving party believes in good faith it has.

If in the course of performing services, the receiving party obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of the disclosing party ("Personal Information") the receiving party agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the services. Furthermore, the receiving party acknowledges and agrees that it will:

a) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as permitted by applicable law;

b) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure; and

c) implement such policies and procedures thoroughly and effectively.

The Service Recipient shall be entitled periodically to conduct reviews of the procedures implemented by the Service Provider in relation to the obligations described in this Section 10.

Upon the termination of the provision of the services each party shall immediately return to the other party all Confidential Information and Personal Information provided by the disclosing party to the receiving party, and all copies thereof in its possession or control (other than such Confidential Information or Personal Information which continues to be used or relevant to the provision of the services), or destroy such information and copies and certify to the disclosing party that such destruction has been carried out.

11. Audit Rights

The Service Recipient shall have the right, at its own cost and by notice to the Service Provider at reasonable hours to examine and make copies of the books, records and charts of the Service Provider to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to any of the provisions of this Agreement and to comply with any government filing requirements. Such books, records and charts shall be preserved in accordance with the records retention policies of the Service Provider, provided the books, records or charts related to any matter disputed between the Parties or which is the subject of an outstanding application or proceeding before a government body shall be preserved until such dispute is settled or such application or proceeding has been finally resolved, whichever is later. The Service Recipient's rights under this Section to view books, records and charts to make copies:

(a) for internal purposes, shall subsist for a period of two (2) years from the end of the calendar year to which such books, records and charts relate, both during the term of this Agreement and for a period of two (2) years after expiration or termination of this Agreement, and

(b) for the purposes of complying with the requirements of governmental bodies, including tax authorities, shall subsist for a period of seven (7) years from the end of the calendar year to which such books, records and charts relate, both during the term of the Agreement and for a period of two (2) years after expiration or termination of this Agreement.

If this Agreement has been terminated or has expired, the Service Provider's obligations to preserve such books, records and charts in accordance with its records retention policy shall continue. The Service Provider may fulfill such obligations by continuing to preserve such books, records, and charts or by delivering them to the Service Recipient.

12. Force Majeure

If either Party is rendered unable by force majeure to carry out its obligations under this Agreement, other than a Party's obligation to make payments to the other Party, that Party shall give the other Party prompt written notice of the event giving rise to force majeure with reasonably full particulars concerning it. Thereupon, the obligations of the Party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than the continuance of, the force majeure. The affected Party shall use all reasonable diligence to remove or remedy the force majeure situation as quickly as practicable.

13. Quantity and Quality of Service

Quantity and quality indicators are included in each Service Schedule appended to the applicable RCAM Confirmation Notice for the year in which the related service is provided. In accordance with section 14 below, the Parties shall review and update the Service Schedules and the RCAM in each year that services are being provided prior to signing the RCAM Confirmation Notice, to ensure quantity and quality indicators are accurately reflected.

The Service Provider shall perform the services in accordance with the Service Schedules, and shall use reasonable efforts to perform the services in accordance with any additional instructions received from the Service Recipient at any time during a year; provided, however, that the Service Provider shall not be required to incur any additional costs related to the request.

14. Performance Reviews

The Parties will conduct performance review meetings annually, at least four months prior to the end of each year in the Term, between personnel of the Service Recipient who receive the services, and personnel of the Service Provider who provide the services. The purpose of these meetings is to assess and report upon whether the services are being delivered in accordance with the Agreement. Any changes to the operating environments, to the extent that they impact, or could impact, service delivery in any way shall be identified, discussed and monitored.

Personnel conducting the performance review meetings shall provide formal written confirmation whether the services are being delivered in accordance with the Agreement (based on the services descriptions and the quality and quantity indicators in the Service Schedules), and a description of any negotiated changes to the services as a result of this review, to each of the Controller's Groups of the Service Provider and Service Recipient prior to October 1 in the year to which the performance review relates. The Parties shall include all negotiated changes in the updates made to the Service Schedules and the RCAM for the following year in which services are provided.

15. Dispute Resolution Process

In the event that the applicable managers of the Parties cannot resolve an issue related to the nature or performance of services, the amount or bases of the cost allocations, or the interpretation of the Agreement within ten (10) business days of the date that written notice of the disputed issue is received by the non-disputing Party from the disputing Party, then either Party may send a written notice of the dispute to the responsible executives to be escalated upward through the respective organizations of the Parties, to Director, Vice-President and/or President, for resolution within twenty-one (21) business days after the receipt by the applicable executive of the notice. If required, the President of the Service Recipient shall make a final determination. The Director of each of the Parties' Controller's Groups shall facilitate this dispute resolution process and ensure that any negotiated changes resulting from the performance review process be incorporated into the updates made to the Service Schedules and the RCAM for the following year in which the Services are provided.

Upon mutual agreement of the Parties, any dispute or issue of interpretation arising hereunder may be jointly referred for non-binding guidance or arbitration to an external facilitator with recognized expertise in the subject matter of the dispute or issue of interpretation.

16. General

The Service Recipient shall be responsible for and shall pay all applicable federal, provincial, municipal goods and services taxes arising from the provision of Services hereunder, including provincial sales tax if applicable.

A Party shall, from time to time, and at all times, do such further acts and execute and deliver all such further deeds and documents as shall be reasonably requested by the other Party in order to fully perform and carry out the terms of this Agreement.

Any notice, request, demand, direction or other communication required or permitted to be given or made under this Agreement to a Party shall be in writing and may be given by hand delivery to the Party to whom it is addressed or sent by facsimile or electronic mail to such party at its address noted below or at such other address of which notice may have been given by such Party in accordance with the provisions of this section.

Service Provider:	Enbridge Inc.
Address:	#3000, 425 – 1st St. S.W. Calgary, AB T2P 3L8
Attention:	Senior Vice President & Controller
Email:	john.whelen@enbridge.com
Facsimile:	403-231-3944
Service Recipient:	Enbridge Gas Distribution Inc.
Address:	500 Consumers Road North York, ON M2J 1P8
Attention:	Vice President, Finance
Email:	narin.kisinchandani@enbridge.com
Facsimile:	416-495-5998

Any such facsimile or electronic mail shall be deemed to have been received at the opening of business at the premises of such addressee on the first business day following the transmission of such notice.

This Agreement may be executed in counterparts, no one of which needs to be executed by both of the Parties. Each counterpart, including an electronic transmission of this Agreement, shall be deemed to be an original and shall have the same force and effect as an original. All counterparts together shall constitute one and the same instrument.

This Agreement will enure to the benefit of and be binding upon the Parties thereto and their respective successors. This Agreement may not be assigned by either of the Parties thereto without the prior written consent of the other.

The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to articles and sections are to articles and sections of this Agreement. Words importing the singular number shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa, and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

In the event that one or more of the provisions contained in this Agreement shall be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality or enforceability of the remaining provisions hereof shall not be affected or impaired thereby. Each of the provisions of this Agreement is hereby declared to be separate and distinct.

This Agreement constitutes the whole and entire agreement between the Parties respecting the subject matter of the Agreement and supersedes any prior agreement, undertaking, declarations, commitments, representations, verbal or oral, in respect thereof.

ENBRIDGE INC.

Per: ______________________
J.K. WHELEN - SENIOR VP & CONTROLER

Per: ______________________
J.R. BIRD - EXECUTIVE VP, CHIEF FINANCIAL OFFICER & CORPORATE DEVELOPMENT

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: ______________________ D. Guy Jarvis
President

Per: ______________________ Mark R. Boyce
Vice President, Law & Information Technology

ENB LL 24510800

REGULATORY COST ALLOCATION METHODOLOGY CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING 2011 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. to Enbridge Gas Distribution Inc. (including Tecumseh Gas Storage) during the year 2011 pursuant to the Agreement, and agree that the services provided, as described in Appendix B hereto, and the costs to be charged as detailed in Appendix A hereto, are acceptable.

TOTAL COST $26,667,504

ENBRIDGE INC.

J.R. Bird, Executive VP, CFO & Corporate Development — Date: February 16, 2012

J. K. Whelen, Senior VP & Controller — Date: February 16, 2012

APPROVED AS TO FORM
ENBRIDGE LAW TP

ENBRIDGE GAS DISTRIBUTION INC.

G. Jarvis, President — Date: MARCH 5, 2012

M. Boyce, VP Law & Information Technology — Date: March 5, 2012

1 PURPOSE

The Regulatory Cost Allocation Methodology ("RCAM") has been developed to determine the allocation of costs from Enbridge Inc. ("EI") to Enbridge Gas Distribution Inc. ("EGD"). The outputs of RCAM are intended to be an input to the rate filings submitted to the Ontario Energy Board ("OEB"). The methodology has been developed by application of sound costing principles and regulatory precedents and has specifically been aligned with the Affiliate Relationship Code for Gas Utilities, originally issued on July 31, 1999 and as amended from time to time (the "ARC").

This RCAM, however, does not replace the existing Corporate Cost Allocation Methodology ("CAM") which will still be used by EI to transfer costs to all its affiliates, including EGD, for internal management and performance measurement purposes.

1.1 About Enbridge

EI is a leader in energy transportation and distribution in North America and internationally. EI operates the world's longest crude oil and liquids transportation pipeline and Canada's largest gas distribution company. EI also operates natural gas transmission pipelines and midstream businesses in the United States and invests in international energy projects. EI's activities are comprised of regulated and non-regulated businesses. The transportation and distribution activities are regulated by the National Energy Board, the OEB, the Federal Energy Regulatory Commission and various provincial and state regulators.

1.2 Need for a Corporate Cost Allocation Methodology

EI's perspective is that an "integrated" operating model reflects the fact that the corporate office is effectively managed as an integral extension of the decision making and operating activities of its business units and affiliates (for the benefit of the business units and affiliates), rather than as a passive "Holding Company" which merely manages a portfolio of investments (for the benefit of the Holding Company shareholders). The impact of this operating model will result in a decreased overall cost of each respective affiliate's operating and maintenance expenses due primarily to the potential for economies of scale. As various functions shift from an affiliate to the Corporate Shared Service Centre the associated cost will be expected to decrease. The resulting corporate cost allocations back to the affiliate would be offset by this reduction in their own incurred costs. For management purposes, these operating costs and benefits need to be tracked.

1.3 Need for a Regulatory Corporate Cost Allocation Methodology

EI recognizes that the objectives of a cost allocation methodology established for internal management and performance measurement purposes may differ from the objectives of a cost allocation methodology established to meet the needs of a regulator, mandated to protect the interests of various rate paying groups.

In recognition of the needs of the regulator, EI has developed the RCAM with the objective of meeting the regulatory requirements of the OEB (as set out in ARC, OEB decisions, and as reflected in industry).

2 DESIGN OBJECTIVES AND PRINCIPLES

The objective of the RCAM is to establish, in the context of Ontario regulation and OEB precedents, the appropriate charges to be allocated for services delivered by EI to EGD in a given fiscal period. These charges are intended to be included in EGD's rate filings.

The methodology will be service based, focused on the needs of EGD and its usage of the services, understandable and transparent, rigorous and practical to administer and supported by verifiable data and records wherever practicable.

2.1 Regulatory Design Principles

Regulators must review and set rates in accordance with their empowering legislation. However, the legislation seldom contains specific guidance on how to set rates. As a result, regulators frequently refer to established regulatory principles to guide their judgment. These key principles include:

- just and reasonable,
- cost of service; and
- prudence.

Just and Reasonable
The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be "just and reasonable". "Just and reasonable" applies to both customers and regulated entities. It requires a weighting of the legitimate interests of both parties.

Cost of Service
Under this principle, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

This principle is consistent with what is expected to occur in a competitive market, where the price of services tend towards the cost of providing them, including a fair return- a principle that has been recognized by the OEB:

> *The Board notes that the general role of the regulator is to act as a proxy for competition. In pricing services in a competitive market the relevant costs would be the costs incurred by the service provider in providing the service, plus an appropriate return in order to attract the capital necessary to provide the service.*[1]

It is important to note that this standard only gives the entity the opportunity to earn a fair return; it does not guarantee it. In most cases, rates are set prospectively, based on anticipated future costs. If the entity over-recovers, it usually keeps the excess. If it under-recovers, it bears the deficiency.

The 'cost of service' principle reflects the need for fairness and the necessity to offer adequate incentives for providing regulated services. That is:

- an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk.

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1 OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2002; Sec. 5.11.49.

However, customers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations.

- from an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract those funds.

Prudence

The prudence standard modifies the "cost of service" standard. Under this standard, customers should be charged only for prudently incurred costs. This recognizes a regulated entity's responsibility to manage itself in a prudent manner and provide regulated services at the most efficient cost.

Prudence is established by determining what a reasonable person would have done in a similar situation. This should not be done while making use of hindsight. A regulated entity's management can be expected to rely only on information reasonably available to it when it makes its decision.

Normally, there is a presumption of management prudence. However, the OEB has stated that this presumption will not apply to transactions between affiliates:

> *… when transactions occur between or among affiliates, the Board will not presume prudence and the onus is on the utility to establish, to the satisfaction of the Board, that the transaction is prudent and that the corresponding costs to the utility associated with the transactions are fair.*[2]

This reflects the potential conflict of interest with such transactions. As a result, regulated utilities must provide adequate support for their intercorporate charges.

In this regard, the OEB has identified what it has referred to as the "three prong test" for Corporate cost allocations, whereby a utility must demonstrate that the charges meet three tests:

- Cost Incurrence - are the proposed charges prudently incurred by, or on behalf of, the utility for the provision of a service required by Ontario ratepayers – i.e., would the utility have incurred the cost if it were operating as a stand-alone utility?,
- Cost allocation - if properly incurred, are the proposed charges allocated appropriately to the utility, based on the application of cost allocation factors and supported by principles of cost causality?; and
- Cost/Benefit - do the benefits to the utility's Ontario ratepayers equal or exceed the costs?

In meeting the third test – Cost/Benefit – the OEB has stated that it would accept four categories of support as a basis for assessing quantifiable benefits:

- Replacement benefits- the services provided replace an equivalent service at equal or lower cost,
- Synergistic or linkage benefits - the services allow the utility to reduce costs by means of being part of a larger organization and operating in concert for the procurement of products and services,
- Revenue enhancement or cost recovery benefits - the utility's activities and capabilities provide value to other affiliates for which payment in cash or kind is received; and

[2] OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2001; Sec. 5.11.30.

- Stand-alone benefits- strategic actions and activities instituted by affiliates that produce direct value to the utility.

2.2 Budget-Based Allocations

As EGD's rates are ultimately based upon a cost of service or rebasing proceeding which uses forward year cost estimates, it is appropriate to similarly use EI's estimated costs, namely its Budget, for the RCAM.
At EI, the budget process is rigorous and the budget is the primary tool managers use for cost control (i.e., the budget process is primarily used to control costs and not the allocation process).

Enbridge budgets costs in three categories based on the notion of grouping cost types:

Department Costs: specific employee and service related costs
General Costs: costs that support several or all business units, but do not relate to one specific affiliate
Direct Costs: costs specifically identifiable to an affiliate

2.3 Regulatory Driven Design Features

Based on regulatory principles and precedents, four key design principles were included in the RCAM design.

- Services Based Approach
- Multi-Step Allocation Process
- Service Description Transparency
- Demand Pull by Recipients

2.3.1 Service Based Approach

The core design principle for the RCAM is the adoption of a service based approach for allocation as required by the OEB and the ARC. The OEB's application of the three-prong test is designed to be applied to service based allocations:

- A utility must demonstrate that all the services associated with the corporate cost allocations are necessary, not just some of the services from a department that charges to the utility or even the majority of the services from a department.
- Where a department supports more than one service and each service has a different causal relationship to affiliates, the services must be broken out so that the most appropriate allocation can de developed for each service provided by that department.
- Cost benefit will be evaluated (wherever possible) by individual service, which requirement is to be discretely defended.

The implication is that each service is fully-burdened with all the costs incurred in delivery. The services costs will therefore include allocations from all applicable department, general and direct budgets. In addition, in some cases certain services may also provide infrastructural or content support to the delivery of other services.

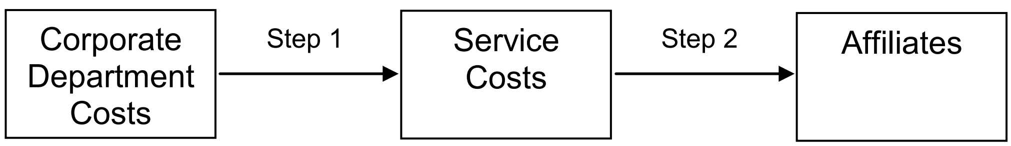
2.3.2 Multi-Step Allocation Process

Using a (fully burdened) service based costing approach also implies that a multi-step allocation process is required. The costs are budgeted at the department level and allocated to each service provided prior to allocation of the fully burdened service cost to the affiliate using the services. Described in its simplest form, the RCAM utilizes a two (composite) step costing approach (See Section 3 for details).

Step 1: At EI, as at most organizations, costs are collected and budgeted in cost centers or departments. Each department offers one or more services. The pool of departmental costs must firstly be allocated to the services provided by the department.

Step 2: Once the services of the department have been costed, a proportion of the cost that represents the actual usage by the affiliate is then allocated to that affiliate.

Figure 1: Two (composite *) Step Allocation Process



* In reality there are a number of sub-steps or sub-allocations that occur. In addition there are a small number of budgeted General Expenses and Direct Charges that are allocated directly as a single step to affiliates.

2.3.3 Service Description Transparency

To enable evaluation of the cost incurrence test, the services provided to the regulated entity must be transparent, both from the recipient, and the provider perspective.

From a recipient perspective, each service must be described in a way that it reflects sub components and the activities involved so that the recipient can evaluate the extent to which the full service is needed.

From a provider perspective, the service must be described in such a way that it is recognizable by every employee delivering the service so that they can assess the relative effort expended and nature of the cost consumed by the service, which will ensure the service can be appropriately costed and will reflect what the provider delivers.

The services provided, and associated expenses (e.g., General Expenses and Direct Charges) and quantity and quality indicators, for any given year are described in detailed Service Schedules appended to the RCAM Confirmation Notice (Schedule 2 to the Agreement), to be signed by both the service provider and service recipient each year.

2.3.4 Demand Pull by Recipients

The RCAM will employ a “demand / pull” approach for allocating service costs. Specifically, the service recipient will pay for only those services required as if it was a stand-alone entity calling for services from an external “arms length” service provider. While both the service recipient and the provider may jointly define the exact nature of those services, ultimately, the recipient will be responsible to confirm the need for the service(s). Through the annual performance review process, the service recipient will confirm that the services being provided meet the service recipient’s requirements, and will ensure that changes are made to those services, if necessary.

2.4 Bases of Allocation

As a general principle, one is seeking to associate and attribute costs (direct and indirect costs) specifically with individual cost objects (in this case, departments, services or affiliates) on the basis of causality.

In reality however, there will be pools of indirect costs that cannot be associated specifically with each one of the cost objects in a group of cost objects. These pools of indirect costs are called "common" costs. In such cases, an allocator that most closely reflects causality must be used.

Allocator definitions for the allocators used in RCAM are included in Appendix A: RCAM Allocator Definitions.

In general, the allocators are selected to reflect:

- the nature of the specific department, service or expense being allocated; and
- the primary drivers of the associated costs.

Primary Cost Drivers

Effort:

Where costs (direct or indirect) have their causal root in effort and can be attributed specifically to each cost object (i.e. departments, service or affiliate) on the basis of time, this allocator (time) will be used, if available.

A quarterly, backward-looking, time study will be used to establish the relative effort expended by EI resources on services provided to EGD and all other affiliates, including EI departments. The time study process will be conducted in a manner consistent with what regulators in earlier regulatory decisions (e.g. Union Gas, TransCanada) have accepted regarding the use of time studies for establishing effort and allocating costs.

In general terms, the time study will be conducted at a detailed level and input sought from each EI staff member within the departments that deliver services to EGD.

For each participating EI department, time estimates are subjected to salary weightings to ensure that departmental costs are appropriately distributed to services and affiliates. Salary weightings are calculated both for the initial allocation to services, as well as for the secondary allocation to affiliates for each service.

The time study will provide an accounting of total time spent by departments on the delivery of services (100 % of staffs' time), as well the proportion of time spent by service on EGD and other affiliates, where identifiable (100% of each staff person's time on a service provided to affiliates). Estimates of the time spent by service will be captured in seven buckets;

- EGD specific;
- EI specific;
- Liquids Pipelines and Major Projects specific;
- Gas Pipelines and Other Distribution specific;
- Sponsored Investments specific;
- International specific; and
- Common time

Usage:

This allocator will be used where costs (direct and indirect) have their causal root in usage and can be attributed specifically to each cost object, on the basis of such usage. The most appropriate allocators include volume metrics such as system users, distance, trips, etc.

Primary Cost Drivers for Common Costs

Where, however, indirect costs cannot be specifically attributed to specific cost objects (which nevertheless provide benefit), the costs may be regarded as "common".

Complexity and Size:

Where these costs have their causal root in effort or usage (and neither specific time nor specific volume metrics can be associated and attributed), allocators will be sought that reflect

- relative complexity of the recipient to be used as a proxy for the likely effort (and hence time) required to service a cost object; or
- relative size of the recipient to be used as a proxy of the likely usage of service (or the likely complexity and hence effort) required to service a cost object.

When indirect costs cannot be attributed to specific cost objects on the basis of time or volume metrics, a relatively small group of allocators will be used. These include derivations of:

- Head Count
- Salaries
- Capital Employed

Relative Benefit:

Where drivers that clearly link to causality are not identifiable, the cost allocators used will be selected to reflect the relative benefit being received by the cost objects in question. The costs incurred were allocated to reflect the benefit experienced by a group of recipients relative to each other.

This is not in conflict with a "cost plus" basis of allocation versus a "market based pricing" mechanism because market based pricing is exactly that; a pricing mechanism, while cost plus is an "apportionment of cost" mechanism.

Stand Alone Principle:

In all cases there will be an underlying intention to allocate costs that are both needed by the recipient (incurrence test) and benefit the recipient (cost benefit test). The costs allocated for the benefit of the service will therefore be equal to or lower than the amount EGD would pay as a stand alone entity for a similar service from an external arms length provider.

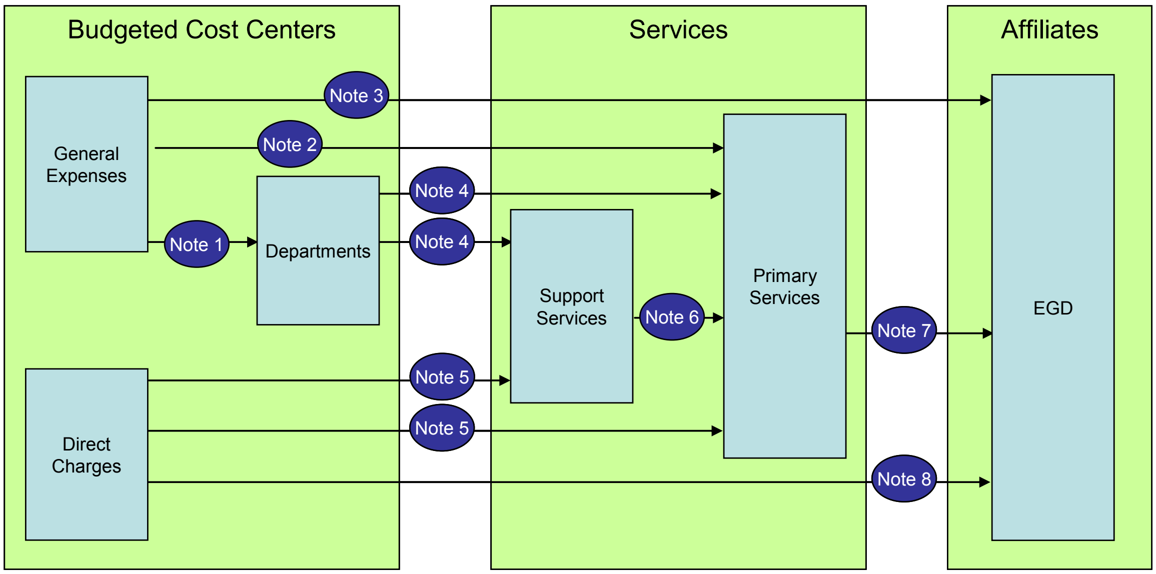
2.5 Currency Usage for Allocations and Direct Charges

Allocations and direct charges will be made in Canadian funds.

3 ALLOCATION

This section reviews the RCAM allocation model. It documents the mechanics and provides a brief rationale for each step.

RCAM Allocation Model



3.1 General Expenses-to-Departments Allocations

Note 1:

EI budgets contain a group of expenses labeled as "General Expenses". These expenses are separately budgeted for management purposes. Some of the General Expenses, however, are incurred for the benefit of Departments (EI only) and some for affiliates. In cases where the General Expenses represent costs incurred by individuals or groups of individuals, the allocation is made to departments in which the individuals reside.

General Expense[1]	Cost Driver	Allocator to Dept
Business Taxes	Usage of facility	Calgary Head Count
Rent & Leases	Usage of facility	Calgary Head Count
Employee Benefits	Usage	Salaries (segmented)
EI's Stock Options (SO), Phantom Stock Units (PSU) and Restricted Stock Units (RSU) Charges[2]	Usage	Head Count - specific
Other Employee Benefits	Usage	Salaries (segmented)
Corporate Law Legal Fees	Staff	Direct
Depreciation - Other Corporate	Direct & Usage	Direct (Plane & IT Projects) Calgary Head Count (other Depreciation)

[1] – General Expenses were not allocated to services provided by EPI and EGD as EI received "fully loaded" allocations from the originating entity.

[2] – Stock Options (SO) Calc: The fair value of stock options is determined at the date of grant using the Black Scholes model. The number of the SOs vested each year is valued at the market price on the date of vesting, minus the grant price for those vested shares.

Phantom Stock Units (PSU) Calc: PSU holders receive notional units as if one unit was one common share. PSU holders receive cash awards following a three-year performance cycle. Awards are calculated for each outstanding unit at the end of the performance period using the EI weighted average share price and a performance multiplier. The performance multiplier is derived through a calculation of specified performance metrics in relation to a specified peer group of companies, relative to targets established at the time of the grant.

Restricted Stock Units (RSU) Calc: RSU holders receive cash per outstanding unit equal to EI's weighted average EI share price at the time of maturity, 35 months from the date of grant. The outstanding units accumulate notional dividends during their validity.

3.2 General Expenses-to-Primary Services Allocations

Note 2:

In cases where the General Expenses are not incurred based on individuals or groups of individuals and are not affiliate specific, the allocation will be made to the services they support.

General Expense	Cost Driver	Allocator to Service
Industry Associations	Usage	Direct
Corporate Secretarial Legal Fees	Usage	Direct

3.3 General Expenses-to-Affiliate Allocations

Note 3:

In cases where the General Expenses can be specifically identified with an affiliate, the costs will be directed to each affiliate respectively.

General Expense	Cost Driver	Allocator to Affiliate
Directors Fees & Expenses	Effort	Capital Employed
Depreciation - Risk Management System (50%)	Usage	System Usage

3.4 Department-to-Service Allocations

Note 4:

All department costs (loaded with applicable General Expenses) will be allocated to the respective services they provide.

In the majority of cases, staff costs represent a significant portion of the department costs and this clearly links effort to causality as the primary driver of the cost of delivering a service. The primary allocator of costs from Department-to-Services in this situation will be "salary-weighted time". (This will include those non-salary costs required to support the Department that are not material in their own right).

In cases where non-salary costs are significant, allocators other than salary-weighted time will be selected and depending on the nature of the costs are allocated (on the basis of causality), either:

- as a direct charge to the respective service; or
- on the basis of usage.

On this basis, all department costs will be allocated on time estimates to the respective services they provide with two exceptions – the Corporate Administration Department and Enterprise Financial System (EFS) Department, as explained below.

1) Due to the materiality of some of the non-salary related costs, the Corporate Administration Department will use:

   - direct allocation of material office administration costs to the Corporate Office Administration Service;
   - direct allocation of maintenance and licence fees related to the HRIS (PeopleSoft), to the Human Resource Information Systems (HRIS) Program Management and Development Service
   - direct allocation of maintenance and licence fees related to the Records Management System (Livelink) to the Records and Information Management Service;
   - direct allocation of maintenance and licence fees related to the Portal Suite of Applications (elink) to the Portal Suite Operations and Technical Support Service; and
   - the remaining costs are allocated based on time estimates to all services provided by the department. (i.e., Corporate Office Admin. Service, Expense System and Supply Chain Management).

2) The costs for supporting the Enterprise Financial Systems (EFS) will be incurred directly by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.

3.5 Direct Charges-to-Services Allocations

Note 5:
The "direct charges" will represent expenses incurred directly by EI which can be tracked on an affiliate specific basis. Direct charges of EI also include allocated costs from EGD and EPI for services provided by them to EI. These costs are added directly into the EI Services. These services will then be reallocated to the affiliates (including EGD and EPI). Where a portion of EGD costs allocated to EI would not be incurred for EGD on its own behalf they will not be re-allocated back to EGD.

3.6 Support Service-to-Primary Service Allocations

Note 6:
In establishing the RCAM, <u>all</u> services provided by EI will be identified, costed and made available to EGD for review. EGD will indicate which services are not directly required by them. Where these services are nevertheless regarded by EI as crucial to support the delivery of the services which EGD does need they are added in to those Primary Services that they support (See Appendix F: Support Service Loading for further service definitions). (The rationale underlying this support services loading is that it makes it comparable to an external service provider establishing a basic infrastructure and operational support to conduct a service delivery business. The costs of such support services will be included in the pricing of primary services to the customers of the external service provider). The distinction between "primary" services and "support" services and the approach to classification is set out below:

Classifying Services as Support vs. Primary:

The following decision chart is used to classify services as either a Primary or Support Service:

Question 1:

Does the affiliate agree that the service is needed directly by them?

- If the answer is "yes" the service is likely to pass the incurrence test as a valid primary service.
- If the answer is "no" a 2nd question will be asked, namely;

Question 2:

Does the affiliate agree that the service is necessary to support the services that are needed directly by them?

- If the answer is "yes" the services is likely to pass the incurrence test to the extent that the service it supports passes the cost incurrence test and is therefore a valid support service.
- If the answer to question 2 "no", then no part of the "support'' service cost will be allocated to the affiliate.

Based on the decision chart established above, the services will be divided into "support" and "primary" services. The nature of each support service will help to determine which primary services receive the costs from each respective support service (i.e., which primary services benefit from the support service). Therefore, the nature of each "support" service is examined and segmented into three groups, namely those that provide "content" based support, those that provide "infrastructural" based support, and those that provide "resource" based support to the primary services.

Loading of Support to Primary Service

Although time estimates were also obtained for determining the extent to which each of the support services were considered to be directly supporting the affiliates, no part of the support service is allocated directly to any affiliate. The full cost of each support service is loaded into the primary services they support. The fully loaded cost of the primary service is then allocated to the affiliate based on the time estimates provided for the respective primary service. Similarly, the common portion would be allocated as determined for the residual of the primary service.

<u>Infrastructural Support Services</u> are considered to be needed by all EI Departments in Calgary providing Primary Services and are therefore allocated across all these Primary Services, based on a Derived Head Count (DHC) of the Primary Service. (Appendix A: RCAM Allocator Definitions)

<u>Content Support Services</u> are allocated to the specific primary services they support based on the relationship of the respective primary service costs. (The DHC of each department is not a reasonable base for allocation for content support services as the volume of people is not the driver of the need for these support services.)

<u>The Resource Support Service</u> is allocated to the services provided by the departments they directly supported as per the time estimation study results.

The summary of support service allocations to Primary Services are listed below:

Support Service	Driver	Allocator
Content Support Services		
Financial Reporting	Complexity & or Usage	Service cost
Certification of Financial Reporting & Internal Controls	Complexity & or Usage	Service cost
Consolidation Accounting	Complexity & or Usage	Service cost
Budgeting & Forecasting	Complexity & or Usage	Service cost
Infrastructure Support Services		
Air Travel for Company Personnel	Usage	Trips[1]
Corporate General Accounting	Usage	Transactions
Corporate Office Administration	Usage	DHC
Environment, Health & Safety	Usage	DHC
Helpdesk, Network, Infrastructure & Hardware Support	Usage	DHC
Information System Support Applications	Usage	DHC
Invoice Processing and Payment	Usage	DHC
IT Project Management & Support	Usage	DHC
IT Software Support & Maintenance	Usage	DHC
Payroll & Benefits Processing	Usage	DHC
Resource Support Service		
Financial Projects	Usage	Direct

[1] Trips – In determining the allocation of the aviation service for transporting company personnel to primary services, the number of flights and the individuals traveling per flight were extracted from the flight logs. With this information and an estimated cost per flight (based on an average cost per km to operate the aircraft and the estimated km traveled per flight) a cost equally shared per individual per flight could be derived. The cost would then track with the individual to their respective affiliate or department and be allocated to the services they support based on the results of the time estimation study. Costs derived in the same manner for each non-Enbridge employee on every flight were treated as a residual corporate cost.

3.7 Service-to-Affiliate Allocations

Note 7:

The link between the basis of allocation and causality is regarded as crucial to the service being able to pass the cost incurrence test. Time is regarded as one of the most supportable causal factors. The methodology therefore seeks to allocate as much of the service cost as possible on the basis of time actually spent delivering the service to affiliates.

Therefore, three broad parameters are considered in the allocation of the cost of the service;

1) How much of the effort spent on delivering the service can be identified and attributable directly to EGD?

2) How much of the effort spent on delivering the service can be identified and attributable directly to other affiliates?
3) How much of the effort spent on delivering the service cannot be identified directly attributable to any affiliate (common cost)?

These proportions have been established by the Time Study.

The effort spent on delivering the Primary Service to EGD versus other affiliates has been identified and used to attribute the portion of the cost of the Primary Service to EGD and other affiliates on the basis of salary-weighted time estimates.

The residual pool of common time is then allocated on a different allocator selected to align as closely as possible to causality.

Not all "common costs" benefit every one of the affiliates. This has specific relevance to the Minority Investments (MIs) which. are sometimes merely financial assets of EI and sometimes fully owned and operated under contracts, etc. The benefiting affiliates will be identified before selecting the allocator which will reflect the most appropriate proxy for causality. See Appendix A for the definition of all acronyms used below.

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
EGD Required Primary Services Provided Solely by EI (i.e. EGD has no capability to self-serve)			
Board of Directors Support	Company complexity & number of meetings	Yes	FCER
Business Development[1]	Mergers & Acquisitions (M&A) activity	No	ACER
Capital Market Financing & Access	Financing activity	Yes	FCER
Cash Management & Banking	Cash volume	No	EGD % of Direct Time[3]
Enterprise IT Program Management	IT programs	No	ACER
Enterprise IT Strategy Planning & Management	IT assets	No	ACER
External Audit Coordination	Audit size (hence company complexity)	Yes	Same as Audit Fees
Government Relations	Regulations	No	ACER
Human Resource Information Systems (HRIS) Program Management and Development	HRIS IT asset usage	No	AHC
Investor Services	M&A and financing activity	Yes	FCER
Rate Regulated Entity Support	Regulation and company complexity	No	N/A
Records and Information Management	Transactions, contracts, documents	No	System Users
Risk Assessment and Management	Entity risk	Yes	FCER

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
Supply Chain Management	Raw material volumes	No	ACER
EGD Required Primary Services Provided as a Supplement to EGD's Own Capabilities			
Audit & Accounting Advice	Company complexity	Yes	FCER
Business & Economic Financial Analysis	M&A activity	No	EGD % of Direct Time[3]
Consolidation and Planning System Technical Support (Khalix)	IT asset usage	No	System Users
Corporate Compliance	Company complexity	No	ACER
Emerging Energy Technology Research	New technologies	No	ACER
Employee and Labour Relations	Employees, Unionized employees	No	AHC
Employee Development	Employees	No	Non Union EFTE
Expense System Management & Technical Support (Oracle iExpense)	IT asset usage	No	System Users
Financial and Project Accounting System Technical Support (Oracle)	IT asset usage	No	System Users
Gas Supply, Storage, and Transportation Strategy	Raw material volumes	No	EGD % of Direct Time[3]
Government Relations	Regulations	No	ACER
Human Resource Advice	Employees	No	AHC
Industry Relations and Corporate Social Responsibility (CSR)	Customer base and public Interest	No	ACER
Insurance Claims Support, Strategy and Management	Entity risk	Yes	Same as Insurance Premiums
Legal Advice	Regulation, Contracts, M&A	No	ACER
Planning, Management & Execution of Internal Audits	Company complexity	Yes	Same as Audit Fees
Portal Suite Operations and Technical Support	Portal IT asset usage	No	System Users
Strategic Planning[2]	Complexity (company & markets)	Yes	FCER
Tax Reporting & Planning	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]
Total Compensation and Benefits	Employees	No	AHC
Primary Services Not Required by EGD			
Aerial Pipeline Surveillance	Not Required by EGD	N/A	N/A

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
External Communications	Customer base and public interest	No	ACER
Gas Accounting	Not Required by EGD	N/A	N/A
Gas Contract Accounting	Not Required by EGD	N/A	N/A
Internal Employee Communications	Employees	No	AHC
Pension Plan Asset Management and Administration	Already charged separately to EGD	N/A	N/A
Reservoir Engineering	Not Required by EGD	N/A	N/A
Tax Advice	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]

[1] Common Business Development Costs accepted by EGD include only the proportion related to costs incurred by the Ontario Business Development department

[2] Common Strategic Planning costs are not accepted by EGD and are regarded as an EI cost

[3] Where time estimates allocated over 80% of the primary service costs specifically to affiliates, it is deemed reasonable to assume the proportion of effort between EGD specific and "Other" specific affiliates was a fair representation for the allocation of the common (to the benefit of all affiliates) effort.

3.8 Direct Charges-to-Affiliate Allocations

Note 8:

EI budgets contain a group of expenses labeled as "Direct Charges". These charges are separately budgeted for management purposes. They, however, are incurred specifically for affiliates and the details may be tracked directly for the benefit of a particular affiliate.

Direct Charges	Driver	Allocator to Affiliate
Depreciation – Risk Management System	Usage/ Transactions	Direct
Direct EFS Charge (Credit)	Usage	Direct
Directors Fees and Expenses	Company complexity & number of meetings	FCER
EGD Stock Based Compensation[1]	Usage	AHC – specific
Insurance Premiums	Risk	Direct

[1] Refer to footnote in Note 1

4 *RETURN ON INVESTED CAPITAL*

ARC allows for a return on "invested capital" as indicated below.

> *2.3.10 Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service,*

product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.

A return on invested capital has not been incorporated as a part of each Primary Services' fully allocated cost, but is included as a separate charge in RCAM.

The "invested capital" has been defined as the NBV (net book value) of PPE (property, plant and equipment) assets of EI required to provide the services.

5 UPDATE AND REVIEW PROCESS

The RCAM is a dynamic document which must be reviewed and updated periodically to ensure its relevance to both EI and EGD to reflect organizational changes of the business and any changes to the regulatory environment. There are five key areas that need to be addressed.

5.1 Service Schedule Detail Reviews

The performance review & evaluation and dispute resolution clauses from the Service Agreement (SA) may highlight changes that need to be reflected in the Service Schedules. While performance feedback may occur throughout the life of the SA, a formal discussion shall take place periodically, at least annually, to ensure changes are documented and incorporated into the next SA and rate case filing. Changes may occur in the service definitions, service offerings by department, expected service deliverables and quality & quantity descriptors.

5.2 Service Review for Relevancy to EGD

The second step in the review process is a review for service relevancy to EGD. Reflecting on the performance feedback process and service schedule reviews, services allocated to EGD shall be reviewed, as part of the performance review process, to ensure that they still meet the cost incurrence test. In addition, services that are currently deemed support services or have not in the past been allocated to EGD shall be reviewed to ensure proper treatment. Changes made to the Service Schedules shall be captured within a revised version of the RCAM, updated annually.

5.3 Time Estimation Study

Once the Service Schedules have been updated with changes highlighted from 5.1 and 5.2, the detailed time estimation study will be conducted, if necessary, to estimate the future time that the EI corporate office will provide to the respective services. The results of the time estimation study are used as an input into the allocation model calculation. The time estimation study will be conducted at the end of each quarter.

5.4 Allocator Review

Concurrently with the time estimation study, a review of the cost allocators will be conducted. This review shall include a determination of whether or not the allocator is still appropriate for use with the service or expense in question, an evaluation of whether the information required for its calculation is available and whether or not the calculation definition needs to be revised based on an organizational change within Enbridge. Changes shall be documented, including the rationale for the change, in a revised version of the RCAM.

5.5 Cost Calculation

Once all Service Schedules are updated, the time estimation study complete and a review of the allocators complete, the cost allocation model shall be revised and run to determine the specific cost allocations from EI to EGD.

Appendix A: RCAM Allocator Definitions

The following table provides the definition of each allocator used in the Regulatory Cost Allocation Methodology ("RCAM") to determine the service charges from Enbridge Inc. ("EI") to Enbridge Gas Distribution Inc. ("EGD"). The allocators are separated into two categories:

1. Allocations to Service: represent allocators used to determine the cost of services.
2. Allocations to Affiliates: represent allocators used to determine service charges attributable to EGD.

Allocator	Definition	
Allocation to Service		
Time (before salary weighting)	Numerator	Sum of all employee time estimates (% of time) from a specific department to a specific service.
	Denominator	Number of employees in the department which provided time estimates.
General Salary Weighting	Salary grade mid-point for individual time study participant from a specific department.	
Salary Weighted Time	General salary weighting for a specific individual multiplied by the individual's time estimate to each service.	
Enbridge Inc. Headcount (EIHC)	Numerator	Number of EI staff of receiving department (including planned full-time and part-time positions for the respective budget year).
	Denominator	All EI staff (including planned full-time and part-time positions for the respective budget year).
Calgary Headcount (CHC)	Numerator	Number of EI staff of receiving department located in Calgary (including planned full-time and part-time positions for the respective budget year).
	Denominator	All staff located in the Calgary office including both EI as well as other affiliate staff (including planned full-time and part-time positions for the respective budget year).
Derived Primary Service Headcount (DHC)	Numerator	Derived HC by Primary Service (By each primary service, sum of head count in each department multiplied by the allocators to service).
	Denominator	All EI staff (including planned full-time and part-time positions for the respective budget year).
		The calculation of DHC does not include any primary service components provided by EGD (e.g. Reservoir Engineering) or EPI as they are deemed already "fully" loaded (e.g. depreciation and 54% burden costs).
Salaries	Numerator	Sum of (Employees in salary range x range mid-point salary) for each salary range in Enbridge Inc. department.
	Denominator	Sum of (Employees in salary range x range mid-point salary) for each salary range in all relevant Enbridge Inc. departments.
Direct		The department cost element, general expense or direct charge is directly loaded into the service which it supports.
Value of Trips	Numerator	Value of corporate jet allocation to a specific Primary Service (derived from time estimation study)
	Denominator	Sum value of all corporate jet allocations to Primary Services.
Financial Project Resource Usage	Allocated equally across the number of Primary Services supported by the Financial Project Support Service.	
Primary Service Cost	Numerator	Specific Primary Service cost prior to support cost loading
	Denominator	Sum of the charges (prior to Support Service cost loading) related to Primary Services which require support services

Allocator	Definition	
Allocation to Affiliate		
Time (before salary weighting)	Numerator A	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to EGD.
	Numerator B	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to Other Affiliates.
	Numerator C	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to All Affiliates.
	Denominator	Number of employees in the department which provided time estimates.
Service Specific Salary Weighting	Numerator	Salary grade mid-point for individual time study participant from a specific department.
	Denominator	Sum of all employee salary grade mid-points, which allocate to a specific service, for a specific department.
Service Specific Salary Weighted Time	Service specific salary weighting for a specific individual multiplied by the individual's time estimate to each affiliate for a specific service.	
EGD % of Salary-Weighted Direct Time	Numerator	Value of direct salary-weighted time-based allocation to EGD.
	Denominator	Value of direct salary-weighted time-based allocation to EGD + Value of direct salary-weighted time-based allocation to Other Affiliates.
Financing Capital Employed Ratio (FCER)	Numerator	EGD's Capital Employed without the Purchase Premium.
	Denominator	Enbridge's Consolidated Capital Employed (including all purchase premiums) plus a gross-up, to reflect full ownership, of EEP, the Saskatchewan Pipeline portion of the Enbridge Income Fund, plus all other Minority Equity Investments.
Adjusted Capital Employed Ratio (ACER)	Numerator	EGD's Capital Employed without the Purchase Premium.
	Denominator	EI's capital employed, without the Purchase Premium, without equity investments but increased to reflect what it would be if EEP and the Saskatchewan Pipeline portion of the Enbridge Income Fund were wholly owned.
Enterprise Full time equivalents (EFTE) or Affiliate Headcount (AHC)	Numerator	Staff of receiving Affiliate (including planned full-time and part-time positions for the respective budget year).
	Denominator	Total staff of all Enbridge Affiliates (including planned full-time and part-time positions for the respective budget year).
Non-Union Enterprise Full time equivalents (Non-Union EFTE)	Numerator	Staff of receiving Affiliate (including planned full-time and part-time positions for the respective budget year) that do not belong to a unionized body.
	Denominator	Total staff of all Enbridge Affiliates (including planned full-time and part-time positions for the respective budget year) that do not belong to a unionized body.
Direct	The general expense or direct charge is directly allocated to the affiliate which causes the expense or charge.	
Audit Fees	Numerator	Value of EGD Audit Fee allocation.
	Denominator	Total Audit Fee budget for Enbridge Inc.
Insurance Premiums	Numerator	Value of EGD Insurance Premium allocation.
	Denominator	Total Insurance premium budget for Enbridge Inc.
System Users	Numerator	Number of EGD system users.
	Denominator	Total system users across all affiliates.
System Usage	Numerator	EGD Transaction volumes + EGD Earnings at Risk.
	Denominator	All Affiliate transaction volumes + All Affiliate Earnings at Risk.

Allocator	Definition
Allocation to Affiliate	
Return on Invested Capital	The "invested capital" has been defined as the NBV (net book value) of PPE (property, plant and equipment) of EI required to provide the services. Calculation: Invested Assets (PPE) for EI x FCER x WACC (EGD's weighted average cost of capital as approved by the Ontario Energy Board from time-to-time).

OVERVIEW – DEPRECIATION OF NET SALVAGE PERCENTAGES

Introduction

1. The purpose of this evidence is to provide an overview of the Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") proposal on treatment of Net Salvage Percentages[1], alternatively known as Site Restoration Costs ("SRC") for the five years from 2014 to 2018. The Company understands both to represent the requirement to collect and accumulate depreciation expense as a liability of future costs to remove assets and restore lands when assets are removed from utility service.

2. The Company filed as part of the 2013 Rates Application (EB-2011-0354) exhibits related to an updated depreciation study. The 2013 depreciation study was a review of depreciation rates with regard to all assets within the Distribution System and did not review the Net Salvage Percentages that determined the amounts of SRC required by the Company. This study as with studies since 2002 was conducted by the consulting firm of Gannett Fleming Canada ULC ("Gannett Fleming").

3. In the Settlement Agreement within the 2013 Rates Application, it was agreed that there would be an extension to the period over which certain assets (Distribution Mains and Distribution Services & Meter Installations) had been historically depreciated.

4. In conjunction with the results of the Settlement Agreement, the Company reviewed the implications of the extended depreciation periods on the

[1] Net Salvage Percentages represent: "the scrap value of the asset minus the related costs of retiring" Depreciation Systems; Wolf, Frank K & Fitch, W. Chester, page 7, 1994

adequacy of the amount of SRCs that had been collected over time. At December 31, 2010, the amount recorded for site restoration costs, on the Company's financial statements, was $723.9 million. In November 2012, the Company requested Gannett Fleming to conduct an evaluation of Enbridge's SRC funding requirements through a Net Salvage Study, and if appropriate, to recommend alternative methods that could be used to determine SRC funding requirements.

5. This evidence provides a summary of Gannett Fleming's analysis and recommendations based on their completion of a Net Salvage Study (filed as Exhibit D2, Tab 1, Schedule 1) and Enbridge's proposed treatment of both prospective collection of Site Restoration Cost amounts and the return of accumulated SRC depreciation reserve variances caused by the change in the procedure used to determine the required net salvage percentages. As detailed in their report, Gannett Fleming has endorsed the use of a Constant Dollar Net Salvage ("CDNS") approach to calculate the required net salvage percentages in the specific circumstances of Enbridge. In simple terms, the CDNS approach is where historic amounts of SRC are revalued by removing the historical inflationary amounts to a current cost and then inflating the current cost by estimates for future inflation.

6. Enbridge has adopted the CDNS approach recommendation, to be effective as of January 1, 2014, which effectively results in recognition that:

    a. The current SRC reserve is greater than required based on today's information; and

    b. The annual accruals for SRC can be reduced for the foreseeable future.

Background

7. Within the depreciation consulting industry, SRC is also known as a Net Salvage Percentage. The Company understands both to represent the requirement to collect and accumulate depreciation expense as a liability of future costs to remove assets and restore lands when assets are removed from utility service. As part of the work completed within a depreciation study, an estimate of the future costs associated with the retirement and removal of assets is made. The regulatory concept of generational equity dictates that the ratepayer who has the benefit of an asset in utility service should be responsible for the total costs associated with the asset including the cost of eventual retirement. As such, it is important to collect the eventual cost of retirement of the assets currently in service over the expected useful life of the assets. To wait until the asset is removed and collect the cost of removal from future ratepayers would unfairly transfer the cost burden from the customer who has received the benefit of the asset to future customers who no longer have the benefit of the asset providing utility service.

8. The SRC liability is made of two elements. First is the portion of the accumulated depreciation reserve amount which is applicable to SRC, and second, is the annual accrual amount that adds to the accumulated depreciation reserve that is specifically applicable to SRC. The amounts of required annual collection amounts, taking into account the amount of the accumulated reserve, are determined through an SRC or Net Salvage depreciation study.

9. Over time, as assets are removed from utility service, the accumulated reserve applicable to SRC is drawn down by the actual costs of retirement at the time of asset retirement. Given that the Company is currently retiring only a small

percentage of its total plant in service in any given transaction year, and also given that the SRC fund is being developed to recover the costs of retirement for all of the assets in service, the accumulated reserve associated with SRC is growing at a faster pace than it is being drawn down.

10. Given: (i) the magnitude of the accumulated reserve for SRC; (ii) the pace at which the SRC reserve is growing; and (iii) the Company's current use of plastic pipes and other assets with relatively longer service lives than assets previously used, the Company requested that additional studies should be completed to determine whether the Company's current approach to SRC requirement is appropriate. Gannett Fleming was commissioned by Enbridge to conduct an SRC or Net Salvage study to determine the appropriateness of the current SRC liability on the balance sheet, and to assess whether different methods could be used to calculate ongoing SRC requirements.

<u>Gannett Fleming Analysis and Recommendations</u>

11. The commissioning of Gannett Fleming was separated into two phases as follows:

    a. Phase 1 was to review the potential that the current net salvage percentages may not be appropriate for the Company's two largest accounts (Distribution Mains and Distribution Services), giving consideration to the increased use of newer generation plastic pipes, and potential changes in installation and removal/abandonment procedures; and
    b. Phase 2 was to undertake a review of alternative methods and detailed calculations of net salvage percentages. Phase 2 was to be completed if

the Phase 1 review indicated that the continued use of the Traditional Approach as used in the previous depreciation studies may not be reasonable.

12. Phase 1 of Gannett Fleming's examination included a high level review of the physical procedures used in the removal of distribution mains and distribution services. Additionally, the historic costs for removal of distribution mains and services were compared to the costs of the anticipated current and future costs for removal. A summary of the findings from Phase 1 is found in Appendix 1 of the Gannett Fleming report (filed as Exhibit D2, Tab 1, Schedule 1).

13. Based on the findings from Phase 1 of the assignment, Gannett Fleming recommended that the continuation of the Traditional Method of determination of the SRC may not be appropriate in the circumstances of Enbridge, and that examination of alternative methods of collection may be appropriate.

14. The key findings from Gannett Fleming that supported their recommendation that examination of alternative methods of collection may be appropriate are:

    a. The current Net Salvage percentages are more negative than equivalent utilities and could result in over-collection for SRC. This is primarily because of the estimated remaining life of the Coated Steel and Plastic Distribution Main Accounts.

    b. The current Net Salvage percentages and methodology have an embedded rate of inflation that is too high due to the inclusion of historic values from the inflationary period in the early 1980s in the traditional net salvage analysis method.

15. The Company accepted Gannett Fleming's Phase 1 findings and requested that Gannett Fleming proceed to complete Phase 2. Phase 2 of Gannett Fleming's examination investigated the following alternative methods of collection:

    a. A <u>"Pause Approach"</u> wherein the annual accrual related to the funding of the accumulated reserve for future removal of plant could be suspended for a short period of time, while the accumulated reserve is allowed to be drawn down;
    b. <u>Application of differing net salvage percentages</u> to original cost of plant currently in service for each specific installation vintage; and
    c. <u>Application of a CDNS approach</u> where all historic transactions are revalued to a current cost to allow for a current cost percentage of net salvage with all impacts of historic inflation removed. The current cost estimate is then inflated using unique estimates for future inflation.

16. In the Recommendations section of their Phase 2 report, Gannett Fleming stated that a CDNS approach to the calculation of net salvage percentages is an appropriate approach to more accurately reflect the future requirement of amounts that Enbridge should accrue for SRC. A summary of the reasons that the other alternative approaches were rejected is provided below, followed by a discussion of the CDNS approach. A more detailed analysis of each of the alternative review is provided in the Gannett Fleming report (filed as Exhibit D2, Tab 1, Schedule 1).

"Pause Approach" Findings:

17. Gannett Fleming did not recommend this approach for two reasons.

18. First, this approach carries a risk of rate shock. The rate shock would arise when Enbridge needed to resume net salvage accruals. Their observation is that the request for resumption of the required level of funding in a future application would carry a significant rate impact to customers.

19. Gannett Fleming also notes that the use of the Pause Approach is not consistent with the regulatory concept of generational equity. In this approach, the current ratepayers would receive a holiday from any amount of funding the future removal of the assets that are in use and contributing to the utility service used by the current ratepayer. Therefore, future ratepayers will be asked to pick up some of the burden of today's costs when the recovery is eventually reinstated.

"Differing Net Salvage Percentages Approach" Findings:

20. Gannett Fleming did not explore this option any further during the Phase 2 review, because the Phase 1 review indicated that future procedures for removal and retirement of plastic and coated steel mains and services will be largely similar to historic practices related to cast iron and bare steel pipe. Enbridge operating procedures are not materially different for the older eras of cast iron and bare steel pipe as with the newer plastic pipe assets.

21. Given the above finding, Gannett Fleming determined that the amount of required funds related to more current vintages are similar to the required funds related to older vintages as future procedures will be largely similar to the historic practices. Therefore, this approach on its own would not result in any material change to the SRC amounts as virtually the same net salvage percentage would be applied to all vintages.

"Constant Dollar Net Salvage Approach" Findings:

22. Gannett Fleming, in making their recommendation for Enbridge to use the CDNS approach in the development of net salvage percentages, noted a number of similarities and differences of the CDNS approach as compared to the Traditional Method. Similarities between the CDNS approach and the Traditional Method are:

    a. Both methods rely on the historic trends of realized costs of retirement as a percentage of original costs retired;
    b. Both methods should be compared against the currently budgeted removal projects; and
    c. Both methods use a rate of inflation to estimate the future costs of retirement at the end of the average remaining life of the account.

23. The two differences in the two methods are:

    a. The cost estimate using the CDNS approach utilizes a forward looking rate of inflation that is based on the current long term economic data. The Traditional Method uses the embedded historic rates of inflation.
    b. The comparison of the current cost of removal to currently budgeted projects in the CDNS approach is a comparison in today’s dollars, whereas the Traditional Method has a significant amount of adjustment required.

24. Based on their review, Gannett Fleming recommended that a CDNS approach to the calculation of Net Salvage Percentages is the preferred approach to more accurately reflect the going forward requirement of amounts that Enbridge

should retain for SRC. The Gannett Fleming recommendation is based on the following:

a. The ability of the CDNS method to normalize the unusually high periods of historic inflation out of the calculations in favor of an estimated and separately developed estimate of future inflation;
b. The CDNS approach specifically utilizes the estimated remaining life of assets currently in service. The plastic pipes installed by Enbridge in more recent periods may have a longer life than the bare steel and cast iron pipes of the past. Therefore, when depreciation studies identify a change in the remaining life estimates, the collection of SRC will likewise be adjusted to reflect the new estimates.
c. The enhanced ability of the CDNS approach to be compared to current budget estimates related to the retirement and removal of assets.

<u>Results of Gannett Fleming Analysis and Recommendations</u>

25. The Gannett Fleming recommended change to the CDNS approach results in an impact to both the accumulated depreciation amount of SRC and the prospective annual amount that is to be collected. The changes to both components of SRC are necessary to effectively transition to an appropriate amount being collected under the CDNS approach. That is because conversion to the CDNS approach results in a situation where: (i) the rate of growth within the SRC reserve does not need to be as high as anticipated within 2013 rates; and (ii) the current amount of SRC reserve is higher than it needs to be.

26. In order to determine the magnitude of the change in the net salvage percentages that may be realized using a CDNS approach, Gannett Fleming

tested the use of the approach on Enbridge's accounts with the largest requirement for future costs of retirement, namely Account 475.00 - Distribution Mains (both coated steel and plastic) and Account 473.00 - Distribution Services.

27. Gannett Fleming's calculation of the impacts with a change to the CDNS approach informed the Company that the annual collection of depreciation expense should be reduced by approximately $30 Million, and that the accumulated depreciation amount should be reduced by a net amount of $259.8 Million. Details of each of these are set out below.

28. The Company has also accepted Gannet Fleming's recommendation that this approach to SRC be reviewed every 3 to 5 years and adjusted if and when it becomes necessary. The Company's proposal is to review the SRC approach at the same time as the expected 2019 rate rebasing application.

Reduction in Annual Depreciation Amount

29. Gannett Fleming's comparison of the impact of the implementation of the CDNS approach with the amounts that would be collected in rates based on the depreciation rates in the 2013 Settlement Agreement shows that implementing the CDNS approach will reduce 2014 depreciation expense by approximately $33.5 Million. Future year depreciation expenses will be lower than they otherwise would be.

30. The changes to reduce the amount of depreciation expense collected annually will be implemented through a change to Net Salvage depreciation percentages. The resulting impacts on depreciation rates can be seen in Table 2 at the end of

this Exhibit. This reduction is an income statement item has been incorporated resulting in a reduction to the Allowed Revenue amounts for 2014 to 2016. The adjustment will also result in a reduction to the Allowed Revenue amounts for 2017 to 2018, both at the time of the filing of the preliminary Allowed Revenue determination and at the time of completing the final 2017 and 2018 Allowed Revenue amounts.

Reduction in Accumulated Depreciation Amount

31. Gannett Fleming determined that the CDNS approach indicates a calculated accumulated depreciation requirement that is a total of $292.8 million less than the requirement using the Traditional Method as of December 31, 2010. That amount may be returned to ratepayers, to bring the accumulated amount to the proper level as part of the transition to the CDNS approach. The total reduction of $292.8 million is made up of an amount included in the reduction in the prospective annual depreciation and a reduction to the SRC reserve or accumulated depreciation.

32. When determining the appropriate amount of SRC needed by the Company, Gannett Fleming looked at both the SRC reserve and the prospective amounts of SRC collection so that at the end of the return period, the amount of SRC reserve would reach the required amount. Gannett Fleming was consistent with past depreciation study practices and the approach that has been accepted by the Board for calculating SRC amounts.

33. In considering the reduction of $292.8 Million in accumulated depreciation reserve over five years, Gannett Fleming takes into account that there is an annual reduction amount of $6.6 Million of the $292.8 Million that is already

included and returned as part of the reduction to the collection of prospective annual SRC amounts. That amount represents an annual adjustment to the $292.8 Million total to account for the fact that returning SRC reserves increases the Company's Rate Base. The $6.6 Million is established as a component of the adjusted Net Salvage percentages that determine the ongoing depreciation rates.

34. Therefore, the total amount of the SRC reserve or accumulated depreciation that is to be reduced ($292.8 Million) is reduced by the $6.6 Million annual amount multiplied by 5. ($292.8 Million less five times $6.6 Million). The Gannett Fleming calculations result in the required reduction to the SRC reserve or accumulated depreciation of $259.8 Million.

35. The sum of the $259.8 Million SRC reserve or accumulated depreciation and the 5 year reduction in depreciation rates of $6.6 Million equals to the total reduction to SRC that Gannett Fleming calculated as the transition to the CDNS approach.

36. Enbridge and Gannett Fleming worked together to find a plan for the transition to the CDNS approach in a manner that is fair to all ratepayers. It was decided that a true-up of accumulated depreciation variances over five years is appropriate, to mitigate rate shock issues while being mindful of inter-generational inequity. In this regard, the Company is proposing an approach that will return the amounts as quickly as is reasonable with the caveat that the final amounts returned do not cause a significant customer bill increase once the return is complete.

37. The Company is proposing that the $259.8 Million be returned to ratepayers so that the amounts in the first years are higher than in the last years. This will mitigate the bill impact when the reimbursement is completed. Table 1 below outlines the proposed annual return amounts that sum up to the $259.8 Million. Gannet Fleming considers that this approach (and the specific amounts included) is reasonable.

Table #1 – SRC Annual Return Amounts

Year	Return Amount ($Million)	Percentage of Total (%)
2014	$68.1	26.3
2015	$63.1	24.3
2016	$58.1	22.4
2017	$53.1	20.4
2018	$17.4	6.7
Total	$259.8	100

38. The Company is proposing to return the amounts set out above through an SRC Rate Rider. The Companywould consider an alternative profile for returning the amounts set out above so long as upon completion of the return there is minimal impact to customer bills the following year. The SRC Rate Rider is the only available mechanism for returning the amounts to ratepayers as theprevious required accounting treatment of the item results in future required accounting treatments such that amounts cannot be returned through an

adjustment to distribution rates. The details of the amounts returned to each rate class are provided in Exhibit H1, Tab1, Schedule 1

39. The following table, Table 2 outlines the impacts of the new depreciation rates as per the Gannett Fleming recommendation that will take effect January 1, 2014.

ENBRIDGE GAS DISTRIBUTION INC.
Impact of the new Depreciation Rates
Effective January 1, 2014

Line No.			Col. 1 Estimated Depreciable Plant Jan. 1, 2014	Col. 2 Test Year Depreciable Plant Dec. 31, 2014	Col. 3 Current Depreciation Rates	Col. 4 Annual Expense Based on Current Rates	Col. 5 Proposed Depreciation Rates	Col. 6 Annual Expense Based on Proposed Rates	Col. 7 Inc/(Dec) in Annual Expense
	Distribution Plant								
1.1	471	Land Rights	7.4	7.4	1.18%	-	1.18%	0.1	0.1
1.2	**472**	**Structures & Improvements**							
1.2a		472 VPC	42.6	46.3	9.93%	4.4	9.93%	4.4	-
1.2b		472 Ottawa (Coventry)	14.7	15.5	4.81%	0.7	4.81%	0.7	-
1.2c		472 Thorold	12.8	14.4	3.61%	0.5	3.61%	0.5	-
1.2d		472 Other	12.5	12.0	2.98%	0.4	2.98%	0.4	-
1.2e		472 Ottawa Depot (SMOC)	2.8	3.0	7.08%	0.2	7.08%	0.2	-
1.2f		472 Old Kennedy Rd	2.3	3.0	23.53%	0.6	23.53%	0.6	-
1.2g		472 Eastern Ave (Stn B)	1.4	1.4	6.86%	0.1	6.86%	0.1	-
1.2h		472 Kelfield	1.4	1.5	7.54%	0.1	7.54%	0.1	-
1.2i		472 Arnprior	0.8	0.8	4.42%	0.0	4.42%	0.0	-
1.2j		472 Brockville	0.5	0.6	4.89%	0.0	4.89%	0.0	-
1.2k		472 Tech Training (Markham)	30.3	31.1	2.18%	0.7	2.18%	0.7	-
1.2l		472 Casselman/Pembroke	-	-	2.98%	-	2.98%	-	-
1.2m		472 New Kennedy/Fleet Garage	-	-	2.13%	-	2.13%	-	
1.2		**Subtotal: Structures & improvements**	**122.1**	**129.6**		**7.8**		**7.8**	**-**
1.3	473/4	Services & Meter Installations	2,270.3	2,355.3	2.98%	69.2	2.45%	57.0	(12.2)
1.4	**475**	**Mains**							
1.4a	475	Mains - plastic	1,627.1	1,691.3	2.74%	45.3	2.17%	35.8	(9.4)
1.4b	475	Mains - coated & wrapped steel	1,155.4	1,272.7	3.46%	45.3	2.80%	37.1	(8.3)
1.4c	475	Mains - cast iron	-	-	91.75%	-	100.31%	-	-
1.4d	475	Mains - other	-	-	23.27%	-	21.38%	-	-
1.4e	475	Mains - envision	143.7	143.7	4.03%	5.8	4.03%	5.8	-
		Subtotal: Mains	**2,926.1**	**3,107.6**		**96.4**		**78.7**	**(17.7)**
1.5	476	Company NGV Refueling Stations	2.6	2.6	5.97%	0.2	5.97%	0.2	-
1.6	477	Regulating Equipment	377.7	402.0	2.14%	8.6	2.10%	8.4	(0.2)
1.7	478	Meters	416.7	425.4	9.22%	38.6	9.22%	38.6	-
1.	**Distribution Plant Subtotal**		**6,122.9**	**6,429.9**		**220.7**		**190.8**	**(30.0)**
	General Plant								
2.1	483.01	Office Equipment	3.1	3.2	0.15%	0.0	0.15%	0.0	-
2.2	483.02	Office Furniture	19.3	23.2	10.74%	2.1	10.74%	2.1	-
2.3	484	Transportation Equipment	49.5	51.8	10.56%	5.3	10.56%	5.3	-
2.4	484.01	NGV Conversion Kits	8.2	8.5	9.00%	0.7	9.00%	0.7	-
2.5	484.02	NGV Cylinders	0.9	0.9	2.10%	0.0	2.10%	0.0	-
2.6	485	Heavy Work Equipment	22.2	22.7	3.58%	0.8	3.58%	0.8	-
2.7	486	Tools and Work Equipment	38.6	39.0	4.08%	1.6	4.08%	1.6	-
2.8	487.70	NGV Rental Refueling Appliances	1.0	2.4	0.74%	0.0	0.74%	0.0	-
2.9	487.80	NGV Rental Refueling Stations	3.5	8.2	8.01%	0.3	8.01%	0.3	-
2.10	487.90	NGV Rental Cylinders	1.9	1.9	18.93%	0.4	18.93%	0.4	-
2.11	488	Communications Equipment	3.9	3.9	9.71%	0.4	9.71%	0.4	-
2.12		**IT Hardware and Software**							
2.12a	490	IT Hardware	36.0	37.8	36.63%	13.0	36.63%	13.0	-
2.12b	490	IT Software Acquired	58.8	59.0	26.32%	15.4	26.32%	15.4	-
2.12c	490	IT Software Developed	55.7	61.6	21.24%	11.9	21.24%	11.9	-
2.12d	490	IT Hardware and Software							-
2.12		**Subtotal: IT Hardware and Software**	**150.5**	**158.4**		**40.3**		**40.3**	**-**
2.	**General Plant Subtotal**		**302.6**	**324.0**		**51.9**		**51.9**	**-**
	Underground Storage Plant								
3.1	451	Land Rights	39.6	39.9	1.16%	0.5	1.16%	0.5	-
3.2	452	Structures and Improvements	19.5	29.9	1.84%	0.4	1.84%	0.4	-
3.3	453	Wells	51.0	52.9	1.49%	0.8	1.55%	0.8	0.0
3.4	454	Well Equipment	9.6	9.6	5.56%	0.5	5.56%	0.5	-
3.5	455	Field Lines	64.2	65.6	1.46%	0.9	1.55%	1.0	0.1
3.6	456	Compressor Equipment	104.3	110.6	2.56%	2.7	2.69%	2.9	0.1
3.7	457	Measurement & Regulating	14.6	14.7	2.94%	0.4	3.04%	0.4	0.0
3	**Storage Plant Subtotal**		**302.7**	**323.1**		**6.3**		**6.5**	**0.2**
4.	**482.50**	**Leasehold Improvements**	**9.0**	**13.9**	**Amortize over the life of the lease**	0.7	**Amortize over the life of the lease**	**0.7**	**-**
5.	**489**	**Software Applications - CIS**	**127.1**	**127.1**	**Amortize - 10 years**	12.7	**Amortize - 10 years**	**12.7**	**-**
6.		**Totals**	**6,864.3**	**7,218.1**		**292.3**		**262.5**	**(29.7)**
7.		**Composite Depreciation Rate**				**4.15%**		**3.73%**	**-0.42%**

MUNICIPAL TAXES

1. Enbridge Gas Distribution's forecast of its 2014, 2015, and 2016 utility property tax expense is $41.2, $43.1 and $45.5 million respectively. These figures reflect recoveries of approximately $0.2m concerning shared facilities for non-utility usage.

CONTINUITY OF UTILITY PROPERTY TAX EXPENSE

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
$ Millions	2016 Budget	2015 Budget	2014 Budget	2013 ADR Budget	2012 Actual	2011 Actual	2010 Actual	2009 Actual
Utility Property Taxes	$45.5	$43.1	$41.2	$39.3	$37.7	$37.4	$37.4	$35.7

2. In establishing these estimates, Enbridge used the 2012 actual calendar year as its benchmark and made adjustments going forward in calendar years 2013 (including $800k reduction agreed to within the 2013 ADR Settlement), 2014, 2015 and 2016 for growth in mains (new/reinforcement/replacement) and additional service connections system-wide based on historical growth amounts, adjusted for inflation. As well, adjustments were made to capture additional taxes for land acquisitions and improvements such as the new safety training facility in Markham, along with Leave to Construct Projects such as the GTA Project.

3. In addition to impacts from forecast growth in the distribution system and other assets, there are a number of drivers that contribute to changes in forecast utility property tax expense in 2014 to 2016.

   a. Review of Enbridge's records resulted in pipeline assessment increases as reported to the Assessment Authorities on March 1, 2013, due to revisions made to "year laid" of numerous mains system-wide, which lowered the depreciation for property assessment purposes as per the pipeline regulated depreciation schedule within Ontario Regulation 338/12.

b. An unfavourable decision was rendered by the Assessment Review Board on June 30, 2011 – File # WR 102472 with respect to the Oshawa Gate Station concerning a property assessment classification appeal, i.e., industrial vs. commercial property classification pursuant to subsection 6.(1)1.i of Ontario Regulation 282/98. This decision impacts municipal taxes for gate stations across Enbridge's system. Accordingly, Enbridge unsuccessfully sought Leave to Appeal to the Divisional Court regarding this matter in August 2012. The impact on municipal taxes for the 2013 and beyond is an increase of approximately $85k per annum.

c. Municipal taxes for the 2013 taxation year will reflect a scheduled provincial reassessment based on current value assessment (CVA) as at January 1, 2012 with increases in CVA over January 1, 2008 being phased-in over a four year period. Also, new pipeline regulated tax rates were established by the Minister of Finance for the 2013, 2014, 2015 and 2016 taxation years as per O.R. 338/12 filed on Nov. 5, 2012. These two factors could cause a potential tax impact to the above noted forecasts due to the initial reassessment in 2013, which will not be known until the final tax bills are issued later in the year.

d. Finally, economic inputs of 1.39%, 1.64% and 1.72% concerning 2014, 2015 and 2016 tax years respectively have been applied for tax inflation purposes. Every 1.0% in tax inflation accounts for approximately $400k per annum in property taxes.

4. Set out below are explanations for the variances in the Municipal Taxes forecast from 2013 to 2016.

<u>2014 Budget vs. 2013 Forecast ($41.2m vs. $39.3m)</u>

5. A tax inflation rate of 1.39% was applied (2014 over 2013) along with increased taxes in growth for new main, reinforcement main, replacement main and new service connections. As noted earlier, the 2013 taxation year will reflect a scheduled provincial reassessment based on CVA as at January 1, 2012 with increases in CVA over January 1, 2008 being phased-in over a four year period.

<u>2015 Budget vs. 2014 Budget ($43.1m vs. $41.2m)</u>

6. A tax inflation rate of 1.64% was applied (2015 over 2014) along with increased taxes in growth for new main, reinforcement main, replacement main and new service connections. As well, additional taxes will be incurred for the GTA Leave to Construct Project in 4thQtr/2015 of $452k.

<u>2016 Budget vs. 2015 Budget ($45.5m vs. $43.1m)</u>

7. A tax inflation rate of 1.72% was applied (2016 over 2015) along with increased taxes in growth for new main, reinforcement main, replacement main and new service connections. As well, further additional taxes will be incurred for the GTA Leave to Construct Project for the 2016 of $912k.

DEMAND SIDE MANAGEMENT (“DSM”) BUDGET

1. In the Company’s 2013 rate proceeding, parties to the Settlement Agreement established a placeholder DSM budget in the amount of $31.4 million (ref. EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, on page 19). This budget was determined by applying the estimated GDP-IPI rate of 1.73% to the 2012 base budget of $30.91 million. Similar to a past proceeding(ref. EB-2011-0354, Exhibit D1, Tab 7, Schedule 1 on page 2), the Company proposes that any increase (or decrease) to the 2013 budget be recorded in the 2013 DSMVA for eventual clearance.

2. In a current DSM proceeding (EB-2012-0394), for the determination of the 2013 and 2014 detailed DSM budgets, an update to the 2013 DSM budget in the amount of $31.6 million is before the Board as part of a Settlement Agreement (decision pending).

3. The Company anticipates adjusting this increase to the 2013 budget of $0.2 million through the 2013 DSMVA, as per EB-2011-0354, Exhibit D1, Tab 7, Schedule 1 on page 2.

4. In the current DSM proceeding, the Company has a 2014 DSM budget in the amount of $32.2 million (decision pending).

5. The Company has increased the DSM budget in 2014 by 2% (ref. EB-2012-0394, Exhibit B, Tab 1, Schedule 2). The same escalation factor has been used to forecast a 2015 DSM budget of $32.8 million, and subsequently, a 2016 DSM budget of $33.5 million. The Company anticipates that the 2015 and 2016 DSM

budgets will be filed as part of the next multi year plan process. The company proposes that any differences between these forecast amounts and amounts ultimately approved be recorded in the DSMVA for eventual clearance.

DEFERRAL AND VARIANCE ACCOUNTS

2013 Test Year Approved Deferral and Variance Accounts

1. The following is EGD's list of 2013 Board Approved deferral and variance accounts ("DA" and "VA"). For the 2013 deferral and variance accounts approved and listed below, EGD will file a separate application requesting a process for the review and proposed clearance of the accounts as soon as feasibly possible following the public release of its fiscal 2013 year-end financial results (in March or April 2014).

2013 Purchased Gas Variance Account ("PGVA"),
2013 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2013 Transactional Services Deferral Account ("TSDA"),
2013 Unaccounted for Gas Variance Account ("UAFVA"),
2013 Storage and Transportation Deferral Account ("S&TDA")
2013 Deferred Rebate Account ("DRA"),
2013 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2013 Average Use True Up Variance Account ("AUTUVA"),
2013 Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"),
2013 Manufactured Gas Plant Deferral Account ("MGPDA"),
2013 Gas Distribution Access Rule Costs Deferral Account ("GDARCDA"),
2013 Ontario Hearing Costs Variance Account ("OHCVA"),
2013 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2013 Open Bill Revenue Variance Account ("OBRVA"),
2013 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2013 Post-Retirement True-Up Variance Account (PTUVA"),
2013 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2013 Demand-Side Management Variance Account ("DSMVA"),

Witnesses: K. Culbert
D. Small

2013 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),
2013 Demand Side Management Incentive Deferral Account ("DSMIDA")

<u>2014 through 2018 Fiscal Year Proposed Deferral and Variance Accounts</u> /u

2. The Company has reviewed the existing required and potential requirement for deferral and variance accounts during the 2014-2018 rate making period and /u proposes the following accounts be established for use during the period. Within the list of accounts, the following are newly proposed accounts, CCSPDA, GGEIDA, CDNSADA, UDCDA, GTAPVA, RLMVA and RPMVA with separate written evidence /u provided within the D1 series of exhibits. The remainder of the accounts have been previously approved, though there are proposed revisions to the ongoing scope of several of these accounts: GDARIDA, OBRVA, TIACDA, TSDA and DSMVA.

2014-2018 Purchased Gas Variance Account ("PGVA"),
2014 Unabsorbed Demand Cost Deferral Account ("UDCDA")
2014 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2014-2018 Transactional Services Deferral Account ("TSDA"),
2014-2018 Unaccounted for Gas Variance Account ("UAFVA"),
2014-2018 Storage and Transportation Deferral Account ("S&TDA")
2014-2018 Deferred Rebate Account ("DRA"),
2014-2018 Customer Care Services Procurement Deferral Account ("CCSPDA"),
2014-2018 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2014-2018 Average Use True Up Variance Account ("AUTUVA"),
2014-2018 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"),
2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")
2014-2018 Manufactured Gas Plant Deferral Account ("MGPDA"),
2014-2018 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA"),
2014-2018 Ontario Hearing Costs Variance Account ("OHCVA"),

Witnesses: K. Culbert
D. Small

2014-2018 Electric Program Earnings Sharing Deferral Account (“EPESDA”),
2014-2018 Open Bill Revenue Variance Account (“OBRVA”),
2014-2018 Ex-Franchise Third Party Billing Services Deferral Account (“EFTPBSDA”),
2014-2018 Post-Retirement True-Up Variance Account (“PTUVA”),
2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”),
2014-2018 Transition Impact of Accounting Changes Deferral Account (“TIACDA”),
2014-2018 Demand-Side Management Variance Account (“DSMVA”),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account (“LRAM”),
2014-2018 Demand Side Management Incentive Deferral Account (“DSMIDA”),
2015-2018 Greater Toronto Area Project Variance Account (“GTAPVA”), /u
2017 -2018 Relocation Mains Variance Account (“RLMVA”) and /u
2017-2018 Replacement Mains Variance Account (“RPMVA”). /u

Following the end of each year (2014 to 2018), EGD will file a separate application requesting a process for the review and proposed clearance of these deferral and variance accounts as soon as feasibly possible following the public release of its fiscal year-end financial results for that year (in March or April of the following fiscal year).

Descriptions of Accounts

Purchased Gas Variance Account ("2014 to 2018 PGVA")

3. The purpose of the PGVA is to record the effect of price variances between actual gas purchase prices and forecast prices which underpin the revenue rates to be charged in each fiscal year. Without this variance account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower

than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This variance account ensures that such effects are eliminated.

4. The Company has outlined the following methodology and scope to be in effect for the determination of amounts to be captured and cleared with respect to the 2014 PGVA. At this time, the basic premise and methodology to be used in determining what is to be included within the 2015 through 2018 PGVA accounts will not likely be materially different than that currently approved. However, the Company is not able to fully define what scope changes will potentially be required as a result of the planned GTA project and its gas supply plan implications. The Company proposes that it will bring forward a methodology scope for each of the 2015 through 2018 PGVAs within the rate adjustment applications for each of 2015 through 2018 (as outlined in evidence at Exhibit A3, Tab 3, Schedule 1).

2014 PGVA Methodology

5. The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada PipeLine Limited ("TCPL") firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded monthly in the PGVA.

6. The fixed cost component of the TCPL firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized long haul

TCPL ("FT") transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual long haul TCPL Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA. However, due to the uncertainty arising from the most recent TCPL decision, the Company is proposing a change for 2014. If the Company enters into alternative arrangements that allow it to satisfy its Peak Day Design Criteria Demand prior to the start of the fiscal year then the Company would propose that if these alternative arrangements impact the amount of forecasted UDC then the Company will amend its forecast and bring forward any changes as part of the January 2014 QRAM.

7. Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TCPL tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized long haul TCPL transportation capacity will also be recorded in the PGVA. The inclusion of changes in TCPL tolls in the PGVA is consistent with past practice.

8. Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based on an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

9. Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TCPL tolls will be recorded in the PGVA as a separate adjustment.

10. For the period January 1 to December 31, 2014, expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2014 PGVA. The PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

11. The PGVA will record adjustments related to Transactional Services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2014 PGVA and 2014 TSDA for purposes of deferral account dispositions.

12. In addition, the 2014 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

13. The 2014 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter within the fiscal year. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

14. The 2014 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

15. The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

16. The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA for each fiscal year.

17. Simple interest is to be calculated on the opening monthly balance of the 2014 PGVA at the approved short-term debt interest rate.

<u>2014 Design Day Criteria Transportation Deferral Account ("2014 DDCTDA")</u>

18. The Company has prepared its 2014 Gas Cost budget inclusive of the impact of the increased requirements resulting from the update of the Peak Gas Design Day Criteria approved by the Board in EB-2011-0354, to be phased in equally over the 2013 and 2014 fiscal years. Consequently, the DDCTDA is not required for fiscal years beyond 2014.

Witnesses: K. Culbert
D. Small

19. The purpose of the proposed 2014 DDCTDA is to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet increased requirements resulting from the Approved changes in the Peak Gas Design Day Criteria.

20. Simple interest is to be calculated on the opening monthly balance of the 2014 DDCTDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Transactional Services Deferral Account ("2014-2018 TSDA")

21. The proposal for the 2014-2018 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related Transactional Services, to be shared 90/10 between EGD's ratepayers and shareholders.

22. While the Company plans to continue to include a forecast of $12.0 million in Transactional Services revenue as an offset to rates, the Company is proposing a change to the derivation of amounts in the TSDA. Given the recent NEB changes within TCPL tolls and unknowns within the future prices and potential related impacts, EGD is proposing an updat to the TSDA methodology and scope. In the event that the ratepayer share of 2014-2018 TS net revenue exceeds $12.0 million, then such amounts over $12.0 million will be credited to the TSDA. In the event that the ratepayer share of 2014 TS net revenue is less than $12.0 million, then EGD will be credited with the difference between the actual ratepayer share of 2014-2018 TS net revenue and $12.0 million. This is a change from the 2013 TSDA. Currently the

maximum credit to Enbridge is $ 4.0 million. The Company is proposing that there be no cap on the amount being credited to Enbridge should the ratepayer share of TS net revenue be less than $12.0 million.

23. Simple interest is to be calculated on the opening monthly balance of the 2014-2018 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Unaccounted for Gas Variance Account ("2014-2018 UAFVA")</u>

24. The purpose of the 2014-2018 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of Unaccounted for Gas ("UAF") and the Board approved UAF volumetric forecast. The Company proposes that for each of these fiscal years, the UAF volume variance calculation will measure each fiscal year's actual UAF against the UAF volume forecast.

25. The gas costs associated with the UAF variance will be calculated at the end of each calendar based on the estimated volumetric variance between the Board approved level of UAF for the subject year and the then-current estimate of the UAF for that year. This amount will be included within the UAF for the subject year. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF used within the prior year's UAFVA and actual UAF experienced for that year.

26. The UAF annual variance would then be allocated on a monthly basis in proportion to actual sales and the related cost would be calculated using the monthly PGVA reference price.

27. Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Storage and Transportation Deferral Account ("2014-2018 S&TDA")</u>

28. The purpose of each of the 2014-2018 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the Company.

29. The S&TDA for each fiscal year will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

30. The S&TDA for each fiscal year will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

Witnesses: K. Culbert
D. Small

31. Simple interest is to be calculated on the opening monthly balance of each of the 2014-2018 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Deferred Rebate Account ("2014-2018 DRA")</u>

32. The Company proposes to establish a DRA for each of 2014-2018, to record any amounts payable to, or receivable from, customers of the Company as a result of the clearing of deferral accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

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

<u>2014-2018 Customer Care Services Procurement Deferral Account ("2014-2018 CCSPDA")</u>

34. The costs approved for recovery in rates by the EB-2011-0226 Decision included Enbridge's major customer care outsourcing and internal O&M costs in addition to the remaining capital and related costs associated with the Enbridge Customer Information System ("CIS")that was implemented in September 2009.

35. The two major outsourced customer care agreements addressed in the EB-2011-0226 proceeding will reach their normal expiry dates as on

December 31, 2017 subject to extension rights available to the Company. The Company is planning on conducting benchmarking and tendering processes with respect to the services conveyed via these agreements beginning in 2014. As such, the Company requests that a new deferral account be established, the Customer Care Services Procurement Deferral Account ("CCSPDA"), to be in effect /u for 2014, 2015 and 2016 to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to new service provider(s). The Company would then bring the costs recorded in this account for recovery in rates in 2017. Further details are provided in the Customer Care Services Procurement Deferral Account evidence at Exhibit D1, Tab 8, Schedule 4.

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

<u>2014-2018 Customer Care / CIS Rate Smoothing Deferral Account ("2014-2018 CCCISRSDA")</u>

37. The CCCISRSDA is required for each of these years to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues. This approach was approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account for 2014 and for each subsequent year through 2018, will be calculated by multiplying the difference in cost per customer and smoothed costs per customer, times the updated customer forecast for the year. The balances in the account will not be cleared during the 2014 through 2018 period. The balance will build up during the years 2013 to 2015

when the cost per customer exceeds the smoothed cost per customer being collected in rates, and then the balance will be drawn down during the years 2016 to 2018 when the cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other 2018 deferral and variance accounts.

38. As determined in the EB-2011-0226 Settlement Agreement, interest is to be calculated on the balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

<u>2014-2018 Average Use True Up Variance Account ("2014-2018 AUTUVA")</u>

39. The purpose of the AUTUVA for each of these fiscal years is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

40. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of

this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Greenhouse Gas Emissions Impact Deferral Account ("2014-2018 GGEIDA")</u>

41. The purpose of the GGEIDA for each of these years is to record amounts associated with any and all impacts of potential Provincial and or Federal regulations in relation to Greenhouse Gas Emission requirements effected onto EGD during these fiscal years along with the impacts resulting from the sale of or other dealings in earned carbon dioxide offset credits. EGD has provided the context for the potential regulation changes in relation to greenhouse gas emissions in Exhibit D1, Tab 8, Schedule 5.

42. EGD is proposing that this new account will take the place of the account which was formerly intended to deal with the potential impacts of any dealings in earned carbon dioxide offset credits which was called the Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"). The CDOCDA was originally approved by the Board in its Natural Gas Generic DSM proceeding, EB-2006-0021.

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

<u>2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")</u>

44. The purpose of the ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the actual utility

return on equity, calculated on a weather normalized basis, is more than 100 basis points over the level of ROE determined by the application of the Board's ROE Formula, the resultant earnings amount above 100 basis points will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following shareholder incentives and other amounts are outside of the ambit of the earnings sharing mechanism: amounts related to the Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to Transactional Services incentives, amounts related to Open Bill program incentives, and amounts related to Electric Program Earnings Sharing incentives. The ESM is non-symmetrical, such that ratepayers will not be responsible for sharing any level of under-earnings.

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

<u>2014-2018 Manufactured Gas Plant Deferral Account ("2014-2018 MGPDA")</u>

46. The Company is proposing to establish a MGPDA for each fiscal year of the IR term in order to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. Amounts recorded in the 2013 MGPDA will be transferred to the 2014 MGPDA. Costs charged to the

account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company’s responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company’s existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

47. The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

48. Simple interest is to be calculated on the opening monthly balance of the MGPDA in each fiscal year using the Board approved EB-2006-0117 interest rate methodology. The balance of this account together with carrying charges will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Gas Distribution Access Rule Impact Deferral Account (“GDARIDA”)</u>

49. The purpose of the GDARIDA is to record all incremental unbudgeted capital and operating impacts associated with the development, implementation, and operation of the Gas Distribution Access Rule and any ongoing amendments to the rule. Such impacts would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs or revenue changes in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

50. The GDARIDA was formerly approved as and known as the Gas Distribution Access Rule Cost Deferral Account, (“GDARCDA”). The Company is proposing a slight alteration of the scope of the account, which is to include all impacts which could arise as a result of ongoing changes in GDAR. As an example, in 2011, the Board approved an amendment to GDAR which prospectively required a change in the manner in which late payment penalties (“LPP”) and related revenue was applied (exempting the application of LPPs in certain situations where they had previously applied). This amendment meant that the manner and level of which LPP revenue was embedded as an offset to EGD’s rates at the outset of its first Generation IR term was too high relative to the level of LPP revenue which would be recovered in 2012 from late paying customers. To address such situations in future years, without knowing what further amendments to GDAR might come about between 2014 and 2018, EGD is proposing that the account is more properly scoped to include all impacts of any amendments to GDAR as opposed to simply including cost related impacts.

51. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Ontario Hearing Costs Variance Account ("2014-2018 OHCVA")

52. The purpose of the OHCVA for each of these years is to record the variance between actual rate proceeding and other proceedings, activities and related expenses and the budgeted level of $8 million for 2014, $6 million for 2015, and $6 million for 2016 contained within this 2014-2018 rate application.

53. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Electric Program Earnings Sharing Deferral Account ("2014-2018 EPESDA")

54. The Company will continue the EPESDA for 2014 to 2018 under the same parameters as established and approved within the 2013 EB-2011-0354 proceeding. The account will be used to track and account for the ratepayer's 50% share of net revenue generated by DSM services provided under contract to the OPA and electric LDCs. Net revenue is determined, using fully allocated costs, as was determined is the DSM guidelines proceeding EB-2008-0346.

55. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Open Bill Revenue Variance Account ("2014-2018 OBRVA")

56. The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account as currently approved for 2013, allows for net annual revenue amounts in excess of $5.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. Within the Open Bill Access Services EB-2013-0099 application and proceeding EGD is proposing to update the terms of the OBRVA. The proposed updated terms are that in the event that net revenues fall below $4.889 million in any one Enbridge fiscal year, then in the remaining fiscal years up to and including the final year of Enbridge's 2nd Generation IR term (2014-2018), Enbridge will be entitled to a credit equal to the total shortfall between actual net revenues and $5.389 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

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

2014-2018 Ex-Franchise Third Party Billing Services DA ("2014-2018 EFTPBSDA")

58. The purpose of the EFTPBSDA is to record and track the ratepayer share of revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

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

2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account ("2014-2018 CDNSADA")

60. The CDNSADA is being proposed by the Company in conjunction with the Depreciation Study review and proposal being made in this case. The depreciation study filed at Exhibit D2, Tab 1, Schedule 1 proposes implementing the constant Dollar Net Salvage method to calculate site restoration cost requirements. As explained at Exhibit D1, Tab 5, Schedule1 this results in a reduction to the net salvage value or depreciation reserve liability recorded on EGD's books of $259.8 million.

61. EGD is proposing this deferral account as the means of recording and clearing annual credit amounts to ratepayers over each of fiscal years 2014 through 2018. The proposal is to clear the following annual amounts, 2014 - $68.1 million, 2015 -

$63.1 million, 2016 - $58.1 million, 2017 - $53.1 million and 2018 - $17.4 million. This proposed pattern of clearance was determined in conjunction with the Company's expert, Gannett Fleming. In addition, EGD also considered the impact of the revenue requirements, coming out of the five year 2014-2018 period, and determined that a greater portion of the balance being cleared in that time frame could help mitigate the bill impacts, to a degree, arising from capital requirements of EGD during the period.

62. Additionally, for each year, EGD will determine the annual amount actually cleared to ratepayers versus the amount the Company proposed were to be cleared. The difference between those amounts will be included within a future year CDNSADA as a debit or credit. The result will be that the projected remaining un-cleared amount would be adjusted annually to ensure that the total amount cleared through the use of this account, upon true up post 2018, would equal the proposed clearance of $259.8 million.

63. The $259.8 million is currently recorded in a liability account which for utility rate base determination purposes is accounted for as an offset against property, plant and equipment. EGD proposes to transfer the total amount to this deferral account and clear amounts on a monthly basis beginning in January of 2014 through December of 2018, through a rate rider as shown and explained in evidence at Exhibit H1, Tab 1, Schedule . EGD proposes and has calculated rate base for the 2014 through 2016, in a manner which debits the deferral account each and every month by the amount to be cleared out of the $259.8 million which results in a required and equal monthly value increase to rate base during these years. This treatment will continue for rate base determinations in 2017 and 2018.

64. Due to the nature of the proposed treatment of this deferral account, which is that the balance in the account will serve as an offset to rate base while it is being cleared through the proposed rate rider to be in effect for 2014 through 2018, EGD proposes that no interest is required to be calculated for this account.

2014-2018 Transition Impact of Accounting Changes DA ("2014-2018 TIACDA")

65. The TIACDA is required to track and record the remaining un-cleared balances associated with Other Post Employment Benefit "("OPEB") amounts in respect of which the Board approved recovery within the EB-2011-0354 proceeding. In that proceeding, the Board approved recovery of an original estimated amount of $90 million evenly at an amount of $4.5 million over 20 years commencing in 2013. The final estimate which EGD recorded in the TIACDA at the end of 2012 was $88.7 million, which EGD will clear evenly over 20 years commencing in 2013. EGD is requesting clearance of $4.4 million in 2013 within its ESM and deferral and variance account review proceeding EB-2013-0046. The same amount will be cleared in subsequent years, including 2014 to 2018.

66. Interest is not applicable to the balance of this account.

2014-2018 Post-Retirement True-Up VA ("2014-2018 PTUVA")

67. The purpose of the PTUVA is be to record the differences between the forecast pension and other post-employment benefit expenses ("OPEBs") of $37.3 million for 2014, $33.8 million for 2015, and $30.9 million for 2016 included within each of those year's forecast Allowed Revenue amount. The annual estimate details and support are found in evidence in Mercer reports filed as Appendices to Exhibit D1, Tab 16, Schedule 1.

68. EGD proposes that, as part of the annual rate adjustment proceedings for 2015 and 2016, it will provide updated forecasts of pension and OPEBs costs for the subject year, which forecast will replace the original forecast within the Allowed Revenue amount for the subject year. The Company believes that this should mitigate the amount of any annual variances.

69. EGD proposes that the 2014 to 2018 PTUVA will operate in a manner that is similar to the manner in which the 2013 PTUVA operates. That is, any variances between forecast and actual expenses will be recorded and cleared from the 2014-2018 PTUVA subject to the condition that any amount in excess of $5 million (credit or debit) will be transferred into a next year's account, so that large variances can be cleared over time. Under this approach, the maximum amount that will be cleared from each annual PTUVA would be $5 million and any remaining amount from each year's PTUVAs would be transferred to a next year PTUVA for future clearance.

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

<u>DSM Related Variance Accounts (3)</u>

2014-2018 Demand Side Management Variance Account ("2014-2018 DSMVA"),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account ("2014-2018 LRAM"),
2014-2018 Demand Side Management Incentive Deferral Account ("2014-2018 DSMIDA")

71. The Company currently has three DSM related deferral and variance accounts for 2014 as approved by the Board in EGD's 2013, EB-2011-0354 rate proceeding and as described and scoped within the Demand Side Management Guidelines for Natural Gas Utilities EB-2008-0346, EB-2011-0295 and EB-2012-0394 DSM related proceedings. The Company proposes to establish that same group of DSM related deferral and variance accounts for 2015 through 2018 but has not yet received direction from the Board in that regard. Additionally, EGD is proposing that any further variances in DSM spending and results, beyond those included within the 2014-2018 forecasts, which occur as a result of Board decisions in any other proceeding or docket be included within each of the 2014-2018 DSM variance accounts. EGD has included the approved or projected level of DSM spending in each of its 2014-2018 forecasts of costs.

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

<u>2015-2018 Greater Toronto Area Project Variance Account ("2015-2018 GTAPVA")</u>

73. The purpose of this variance account is to track and record the variance which may occur annually between the forecast GTA related Allowed Revenue embedded within EGD's overall Allowed Revenue amounts in this rate application and the eventual actual GTA related Allowed Revenue amounts which occur in each of 2015 through 2018, once the actual impacts of the project are known. Details of the planned GTA project and the proposed variance account are found in evidence at Exhibit D1, Tab 8, Schedule 2.

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

Criteria for Establishment of Deferral and Variance Accounts

75. The criteria adopted by the Company in determining when to come forward for a rate order or an accounting order request for a deferral or variance account includes the following considerations:
    - the materiality of the amount at risk (revenue or expense);
    - protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;
    - the level of uncertainty associated with a forecast of the amount at risk; and
    - the aspect of control - are the underlying circumstances beyond the Company's ability to control.

UPDATED DEFERRAL ACCOUNT EVIDENCE

Unabsorbed Demand Costs Deferral Account (UDCDA) and DDCTDA

76. As described in its updated gas cost evidence at Exhibit D1, Tab 2, Schedule 1, the Company intends to contract for incremental one year long haul FT capacity on TCPL to meet its Peak Day requirements in 2014. A consequence of contracting for incremental long haul capacity is the possibility of Unabsorbed Demand Charges ("UDC").

77. To the extent that the Company is unable to utilize 100% of its contracted long haul TCPL FT capacity to meet customer demand and/or fill storage then the associated UDC costs will be debited in the UDCDA deferral account (excluding the amounts that will be captured in the DDCTDA – please refer to the Updated Exhibit D1, Tab 2, Schedule 1). Enbridge's forecast of UDC costs for 2014, excluding amounts that may be recorded within the 2014 DDCTDA, is $62.8 million. That is the maximum amount that may be recorded within the 2014 UDCDA.

78. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2014 DDCTDA and the 2014 UDCDA. For example, Enbridge will use transportation capacity to fill storage (by displacing discretionary purchases of gas at Dawn) where that is reasonably possible, to reduce the total amount of unutilized capacity. Where there is unutilized capacity, Enbridge will make best efforts to assign that capacity to third parties, to mitigate the UDC costs. The outcome of Enbridge's best efforts to mitigate UDC will be reflected in the amounts recorded in the 2014 DDCTDA and the 2014 UDCDA.

79. Simple interest is to be calculated on the opening balance of this account at the approved short-term debt interest rate.

Witnesses: K. Culbert
D. Small

80. In order to keep the Board and interested parties informed as to the total unutilized transportation costs the Company intends to provide the actual balance in the UDCDA and DDCTDA and the applicable interest through the QRAM process.

81. The Company proposes that as part of the April 2015 QRAM (or subsequent QRAM depending upon the clearance of the 2014 ESM) to clear the 2014 balance in the UDCDA and DDCTDA either through a onetime charge or over the subsequent 12 months which is consistent with the clearance of PGVA balances.

Witnesses: K. Culbert
D. Small

RELOCATION MAINS VARIANCE ACCOUNT (“RLMVA”)

82. As described in its Updated Rate Adjustment Process evidence filed at Exhibit A2, Tab 3, Schedule 1, the Company is now proposing to eliminate Phase I of the 2017 Rate Adjustment Application (through which capital spending requirements for 2017 and 2018 were to be set), and instead plans to set Allowed Revenue for all years of the IR term in this proceeding.

83. As part of the updated Customized IR Plan, the Company is proposing this variance account for 2017 and 2018 to address the unpredictable capital costs in relation to relocation mains requirements beyond fiscal 2016.

84. The evidence explaining the proposed manner in which the account will operate is filed in evidence at Exhibit D1, Tab 8, Schedule 6.

Witnesses: K. Culbert
D. Small

REPLACEMENT MAINS VARIANCE ACCOUNT (“RPMVA”)

85. As described in its Updated Rate Adjustment Process evidence filed at Exhibit A2, Tab 3, Schedule 1, the Company is now proposing to eliminate Phase I of the 2017 Rate Adjustment Application (through which capital spending requirements for 2017 and 2018 were to be set), and instead plans to set Allowed Revenue for all years of the IR term in this proceeding.

86. As part of the updated Customized IR Plan, the Company is proposing this variance account for 2017 and 2018 to address the unpredictable costs in relation to replacement mains requirements in fiscal 2017 and 2018 that are identified through pipeline inspection activities.

87. The evidence explaining the proposed manner in which the account would operate is filed in evidence at Exhibit D1, Tab 8, Schedule 6.

Witnesses: K. Culbert
D. Small

UPDATED PROPOSED GTA PROJECT VARIANCE ACCOUNT

Overview

1. The purpose of this evidence is to explain the variance account which the Company is proposing to be attached to or coincident with the GTA project. As a result of the Company's proposed Updated Rate Adjustment Process as outlined in evidence at Exhibit A2, Tab 3, Schedule 1, the GTAPVA is now required for the years 2014 to 2018 within this rate application.

2. The GTA project rationale is filed within EGD's EB-2012-0451 Leave to Construct Application currently before the Board. Attached as Appendix A to this Exhibit (to be updated by early January 2014), EGD has provided the forecast allowed revenue amounts of the total GTA project for each of 2014-2018, using the GTA project costs and timing assumptions[1](excluding gas cost forecasts and impacts) as embedded within EGD's overall Allowed Revenue for these years.

3. EGD is proposing that this variance account will be used to report any variance between the forecast Allowed Revenue in Appendix A and the eventual actual Allowed Revenue which will be known upon completion of the project. The Company proposes that the Allowed Revenue variance impact for the fiscal years 2015 through 2018 be recognized within the variance account with an offsetting annual entry through revenue in each year, with the cumulative impact at the end of each of 2015 to 2018 to be cleared through a rate rider along with any and all other deferral or variance accounts for the subject year.

[1] The GTA project timing and costs used within the revenue requirements provided are those used within the responses to interrogatories within the GTA LTC proceeding (EB-2012-0451) which assume Segment A's Bram West to Albion is a 36" pipeline with a 50/50 sharing agreement with TCPL.

4. The scale of the GTA project results in the normal forecasting variance of costs potentially being large in an absolute sense. With the forecast of capital costs being $580.9 million (shown in attached Appendix G) even a modest forecast variance could result in a risk to both the ratepayers or the Company of a significant over or under payment and recovery of Allowed Revenue over the 2015 through 2018 fiscal years, which is the principal rationale for the requested variance account.

5. The GTA project consists of two Segments, A[2] and B, which are projected to have construction commence in 2014 / 2015 with an in service date of October 2015. Please refer to the following exhibits filed in the GTA Leave to Construct Application (EB-2012-0451), in order to provide the project details which underpin and support the total GTA project forecast 2014-2016 Allowed Revenue scenarios provided herein at Exhibit C1, Tab 5, Schedule 1, on Appendices A to E:
   - Purpose, need and timing filed as Exhibit A, Tab 3, Schedule 1;
   - Natural Gas Demand, Supply & Expected Benefits filed as Exhibit A, Tab 3, Schedule 5;
   - Proposed Facilities, Operation & System Benefits filed as Exhibit A, Tab 3, Schedule 6;
   - Timing filed as Exhibit A, Tab 3, Schedule 8;
   - Total Estimated Project Cost filed as Exhibit C, Tab 2, Schedule 1;
   - Proposed Construction Schedule filed as Exhibit C, Tab 2, Schedule 2;
   - Arrangement with TransCanada filed as Exhibit E, Tab 1, Schedule 2.

6. EGD has also provided, as Appendix B (to be updated by 2013-12-17), the forecast Allowed Revenue impact of the shared Segment A BramWest to Albion pipeline portion of the overall project as embedded within the EGD overall Allowed Revenue for 2014-2018. EGD proposes to treat the shared Segment A BramWest to Albion pipeline as a separate cost center where a rate (332) will be developed on a cost-of-service basis. Rate 332 would recover the Allowed Revenue associated with any approved ratio of the shared Segment A BramWest to Albion pipeline and would

[2] Same as footnote 1.

Witnesses: K. Culbert
C. Fernandes

exist over the agreed contractual terms with sufficient termination provisions to ensure any unrecovered capital amounts are not unduly cross-subsidized by EGD ratepayers.

7. The Allowed Revenue for the shared Segment A BramWest to Albion pipeline as shown in Appendix B includes the associated cost of capital, O&M, depreciation, and related taxes that occur in each of fiscal years 2015 to 2018.

CONSTANT DOLLAR NET SALVAGE ADJUSTMENT DEFERRAL ACCOUNT ("CDNSADA")

1. Within Exhibit D1, Tab 5, Schedule 1, Enbridge Gas Distribution ("EGD" or the "Company") has filed evidence which results from and supports proposed changes to the current approved depreciation rates and a proposed reduction in the amount of net salvage value or depreciation reserve recorded in the Company's financials. The Company's proposal is based on a review and updated Depreciation Study and proposed methodology performed by depreciation expert, Gannett Fleming. The Gannett Fleming study is found at Exhibit D2, Tab 1, Schedule 1.

2. The CDNSADA is being proposed by EGD in conjunction with the proposed changes identified within the Depreciation Study. One of the proposed adjustments is a reduction to the level of net salvage value or depreciation reserve which EGD has recorded to date. The study proposes an adjustment to that level by reducing the balance currently recorded by $259.8 million over the course of a prospective five year period.

3. EGD is proposing this deferral account as the means of recording and clearing annual credit amounts to ratepayers over each of fiscal years 2014 through 2018. The proposal is to clear the following annual amounts, for 2014 - $68.1 million, 2015 - $63.1 million, 2016 - $58.1 million, 2017 - $53.1 million and 2018 - $17.4 million. This proposed pattern of clearance was determined in conjunction with Gannett Fleming. In addition, EGD also considered the impact of the Allowed Revenue amounts coming out of the three year 2014-2016 period and determined that a greater portion of the balance being cleared during that time frame could help mitigate the bill impacts, to a degree, arising from capital requirements of EGD during the period.

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

4. Additionally, for each year, EGD will determine the annual amount actually cleared to ratepayers versus the amount the Company proposed were to be cleared. The difference between those amounts will be included within a future year CDNSADA as a debit or credit. The result will be that the projected remaining un-cleared amount would be adjusted annually to ensure that the total amount cleared through the use of this account, upon true up post 2018, would equal the proposed clearance of $259.8 million.

5. The $259.8 million is currently recorded in a liability account which, for utility rate base determination purposes, is accounted for as an offset against property, plant and equipment within specific asset related accumulated depreciation categories. EGD proposes to transfer the total $259.8 million amount to this deferral account and clear amounts on a monthly basis beginning in January of 2014 through December of 2018, through a rate rider as shown and explained in evidence at Exhibit H1, Tab 1, Schedule 1. EGD proposes and has calculated rate base for 2014 through 2016, in a manner which debits the deferral account each and every month by the amount to be cleared out of the $259.8 million with a resulting equivalent monthly value increase within rate base during these years. This proposal presumes that the same approach will be followed for rate base determination in 2017 and 2018.

6. The 2014-2016 adjustments to rate base can be seen within the various accumulated depreciation asset related accounts within Exhibits B3, B4 and B5, Tab 1, Schedule 2, pages 3 and 5.

Witnesses: K. Culbert
S. Kancharla
B. Yuzwa

CUSTOMER CARE SERVICES PROCUREMENT DEFERRAL ACCOUNT (“CCSPDA”)

1. In 2011, the Company made an application to the Board, EB-2011-0226, to approve the majority of its customer care related costs for the period from January 2013 through December 2018. This proceeding resulted in a negotiated settlement between the Company and intervenors that was approved by the Board on September 8, 2011. The costs approved for recovery in rates by the EB-2011-0226 Decision included Enbridge’s major customer care outsourcing and internal O&M costs in addition to the remaining capital and related costs associated with the Enbridge Customer Information System (“CIS”) that was implemented in September 2009.

2. The two major outsourced customer care agreements addressed in the EB-2011-0226 proceeding will reach their normal expiry dates as on December 31, 2017 subject to extension rights available to the Company. As such, the Company is planning on conducting benchmarking and tendering processes with respect to the services conveyed via these agreements beginning in 2014. These processes will be necessary to test the marketplace for the outsourced services to confirm the validity of pricing and quality for such services and where appropriate identify new service provider(s). It will be necessary to begin this work early enough in the upcoming IR period so that, if required, new service providers can be transitioned into place by the end of 2017.

3. Based on the Company’s experience with such tendering processes, it is expected that such an exercise will require approximately eight months to complete and will necessitate considerable effort on the part of both internal and external resources. It is estimated that the cost of a full benchmarking and request for

proposals process will be on the order of $4 million to $5 million. The costs associated with this work were not included in the EB-2011-0226 settlement.

4. As such, the Company requests that a new deferral account be established, the Customer Care Services Procurement Deferral Account ("CCSPDA"), to be in effect for 2014, 2015 and 2016 to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to new service provider(s). The Company will bring forward the costs recorded in this account for recovery in a future rate proceeding.

GREENHOUSE GAS EMISSIONS IMPACT DEFERRAL ACCOUNT (“GGEIDA”)

Overview

1. The Ontario Ministry of the Environment (the “Ministry”)is continuing to develop a provincial greenhouse gas emissions reduction program. In January of 2013, the Ministry issued a Greenhouse Gas Emissions Reduction in Ontario discussion paper. The paper was to be used in supporting discussions and seeking comments and input from stakeholders, which were to be received by April 21, 2013, for the purpose of informing the development and design of the program. A copy of the Discussion Paper is filed as Appendix A of this Exhibit.

2. The Ministry recommended an intention of the program being in place in 2015, one year prior to the implementation of Federal regulations of greenhouse gas emissions, which according to the Ministry are expected to begin in 2016.

3. EGD is seeking approval of a Customized IR plan for a 2014 through 2018 period. While EGD has become aware of the intended timeline of the Ministry’s program, the requirements and potential ramifications of the program to EGD and its ratepayers are currently unknown. As a result EGD believes it is appropriate to establish this deferral account as it is unable to analyze and account for any impacts the program might have on EGD within the 2014-2018 timeframe or in any future year beyond that timeframe.

4. At the same time, EGD currently has a Board approved 2013 Carbon Dioxide Offset Credit Deferral Account (“CDOCDA”) which had originally been approved by the Board in EB-2006-0021 and EB-2007-0615 for fiscal year 2008 and then was additionally approved for each of fiscal years 2009 through 2012 by the Board in

subsequent proceedings. As a result of the Ministry of Ontario developing its Greenhouse Gas Emissions Program, EGD is requesting that the CDOCDA be discontinued for 2014 and beyond and that any credits or cost related impacts of Carbon Dioxides be dealt with within the GCEIDA, along with any impacts of the overall Ontario Greenhouse Gas Emissions Program.

5. EGD will bring forward its proposal for the detailed use of the GGEIDA in a future fiscal year if and when the Ontario Ministry of the Environment puts in place regulations concerning any policy outcome.

Greenhouse Gas Emissions Reductions in Ontario

A Discussion Paper

Ontario

Prepared by:
Ontario Ministry of the Environment

Last Revision Date: January 2013

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Overview

Climate change threatens the natural environment that sustains us. Governments around the world recognize this and are reducing greenhouse gas emissions to mitigate the effects of climate change and focussing on sustainable development to help industries stay competitive in the emerging low-carbon economy.

Ontario continues to develop a provincial greenhouse gas emissions reduction program that will achieve real reductions and support Ontario's economic goals. With the Canadian government launching its approach to regulating greenhouse gases, however, the context for taking action has evolved.

The federal government has finalized a regulation for coal-fired electricity generation. This regulation will not affect coal-fired electricity generators in Ontario as they are on track to be phased-out prior to the federal regulation coming into effect in 2015. However, additional federal regulations are expected in the future and could impact other Ontario sectors, including natural gas-fired electricity generation. Federal consultations are now underway with large industrial emitters and draft federal regulations, for some of these sectors, are expected in the fall of 2013.

The province intends to seek equivalency with federal regulations to avoid duplication and allow Ontario to regulate greenhouse gases in a way that works for our industry, our environment and the economy.

Ontario already has ambitious greenhouse gas reduction targets that will require broad action from all sectors including electricity generators and other large emitters. The greenhouse gas emissions reduction program will focus on environmental outcomes and provide flexibility for businesses to develop their own compliance strategies while ensuring that, overall, emissions decrease.

We have done a great deal of work to date in Ontario to reduce emissions and implement effective adaptation strategies for a changing climate. We continue to make significant progress in several key areas, including phasing out coal, developing cleaner energy, and expanding public transit. It is estimated that current initiatives for reducing greenhouse gases will provide approximately 60 percent of the reductions required to meet our 2020 target. A made-in-Ontario greenhouse gas emissions reduction program will not close that gap by itself but will be an important next step towards meeting the province's goal of being 15 per cent below 1990 emissions levels by 2020.

Over the coming months, the ministry plans to engage stakeholders, including the large emitters and other interested parties such as environmental non-governmental organizations and the financial sector, to inform the development and design of the program. The ministry will also be welcoming feedback from Ontario's First Nation and Métis communities.

1.0 Introduction

The purpose of this discussion paper is to support our dialogue on what could be the key elements of a greenhouse gas emissions reduction program that achieves reductions while supporting the province's economic goals. It will also be important to develop a program sufficient for negotiating equivalency with the federal government. The potential approaches contained in this paper should be considered as a starting point for discussions over the coming months.

Ontario has been working since 2009 to develop a program to reduce greenhouse gas emissions from industry that protects the environment and works for the economy. In 2009, the *Environmental Protection Act* was amended to provide for a greenhouse gas emissions reduction program that could link with other systems.

Also in 2009, Ontario introduced a regulation requiring large emitters to report their greenhouse gas emissions. The Ministry of the Environment has now collected data for 2010 and 2011 with the 2011 data verified by a third party. This information is essential for informing the key design elements of a greenhouse gas emissions reduction program.

The ministry is now ready to discuss the possible scope, emissions reduction targets and objectives being considered for the program.

Greenhouse Gas Data

On November 15, 2012, Ontario released greenhouse gas emissions data for regulated facilities for the year 2010.
http://www.ene.gov.on.ca/environment/en/category/climate_change/STDPROD_085095.html

Please consult Ontario's *Greenhouse Gas Emissions Reporting* regulation for details on reporting requirements.
http://www.e-laws.gov.on.ca/html/source/regs/english/2009/elaws_src_regs_r09452_e.htm

Achievements in Emissions Reduction and Adaptation Initiatives; our 2012 Climate Change Progress Report

In this year's report, we outline our achievements to date, the state of our programs in progress and plans for future emissions reductions and adaptation initiatives. We continue to make significant process in several key areas, including phasing out coal, putting in place cleaner energy, and expanding public transit. It is estimated that current initiatives to reduce greenhouse gas emissions will deliver 60 percent of the reductions needed to reach the province's 2020 reduction target. A greenhouse gas emissions reduction program alone will not close the gap but is an important step in that direction.

To learn about other actions the government has taken on Climate Change, please consult our Climate Change Progress Report released on November 13, 2012.
http://www.ene.gov.on.ca/environment/en/resources/STDPROD_101104.html

2.0 Jurisdictional Update

All over the globe, programs to reduce greenhouse gas emissions are being developed and implemented. The federal government and provinces, including Alberta and Quebec, are taking action to address greenhouse gas emissions from emissions-intensive, trade-exposed industries. Thirty European countries have been using market-based greenhouse gas reduction programs since 2005 and markets are operating or in development in Australia, China, Japan, Kazakhstan, New Zealand, California, Quebec and South Korea.

United States

The U.S. Environmental Protection Agency (EPA) is required to regulate greenhouse gas emissions after a Supreme Court decision that greenhouse gases pose a threat to human health. In January 2011, new permitting requirements for large new and modified facilities were implemented. The U.S. EPA also proposed performance standards for new fossil-fired electricity generation in March 2012. Standards are expected for petroleum refineries and other emissions intensive industries but the timing is unclear.

In the Northeast United States, the Regional Greenhouse Gas Initiative (RGGI) has been in place since 2009. It is a program currently restricted to fossil–based electricity generation with emissions trading offering a flexible approach to emissions reductions. The program has been operating successfully for three years and is currently undergoing a planned review. According to its latest report, RGGI investments made from 2009 to 2011 have resulted in the elimination of 12 million tonnes of carbon dioxide while generating $1.3 billion USD in lifetime energy bill savings.[1]

California has developed an emissions trading program that started in 2012, based on a design developed with the Western Climate Initiative. The Western Climate Initiative is a collaboration of independent jurisdictions, including Ontario, working together to identify, evaluate, and implement emissions trading policies to tackle climate change at a regional level. California's approach covers large emitters initially, including electricity generators, and then expands later to include fuel suppliers. Emissions limits are set to take effect January 1, 2013. California raised $288 million USD at its first auction of allowances in November 2012 and is also working towards linking with Quebec's program.

[1] Investments of Proceeds from RGGI CO2 Allowances; February *2011*

Other Provinces' Actions

A 2012 report from the National Round Table on the Environment and the Economy and a 2012 emissions forecast from Environment Canada noted that while emissions are expected to decline or stabilize in Ontario, emissions from other parts of the country are expected to grow.

In Canada, several provinces are taking action to address emissions from large emitters. British Columbia has had a carbon tax in place since 2008 and is a member of the Western Climate Initiative. (NOTE: A carbon tax is not an approach that is being developed in Ontario). Alberta has had an intensity-based emissions trading program since 2007. In 2010, Saskatchewan introduced its draft emissions trading regulation for electricity and industry. Manitoba is consulting on its climate change approach and is a member of the Western Climate Initiative. Nova Scotia has an electricity regulation that requires emissions to be reduced 25 percent from 2010 to 2020. Finally, Quebec has had a carbon levy in place since 2007 and is a member of the Western Climate Initiative. Quebec has its final emissions trading regulation in place with compliance beginning in 2013 and has made amendments to allow linking to California's system.

Canadian Government Action

The Canadian government is developing regulations on a sector-by-sector basis. This intensity-based approach (i.e., tonnes of CO_2 per tonne of product produced) could allow overall emissions to increase as production grows. The first of these regulations covers emissions from coal-fired electricity generation and was finalized in September 2012. The federal government is also planning to regulate other emissions intensive industries. Consultations are currently underway for oil and gas, fertilizer manufacturing, steel, cement, chemical, pulp and paper sectors and may extend to other sectors in the future.

Equivalency

Similar to the approach taken by other provinces that are working to reduce emissions, Ontario has indicated its interest in an equivalency agreement with Canada. Under such an agreement, federal regulations would not apply where Ontario regulations achieve the same or better environmental outcomes.

Ontario has a mature and robust regulatory framework in place including its local air quality regulation and emissions trading program for air pollutants (limiting nitrogen oxides and sulphur dioxide). Ontario will be working towards an equivalency agreement that provides flexibility to industry and supports an integrated and efficient approach to reducing air pollutants and greenhouse gases.

Ontario's approach will ensure reductions are achieved and provide a variety of compliance options such as reducing emissions by investing in new technology, switching to lower carbon fuels, or buying offsets or allowances. Designing a program that works for Ontario will be the focus of our discussions with stakeholders in 2013.

3.0 Principles and Goals for Development of a Program

The program elements presented for discussion have been developed based on a set of key principles aimed at protecting the environment while considering Ontario's economic outlook. These principles include:

- Achieving absolute reductions in greenhouse gas emissions in a cost-effective way that considers competitiveness and supports achieving equivalency with the federal government
- Simplicity, consistency, transparency and administrative efficiency
- Striving to treat sectors and facilities equitably
- Taking into account early action by industry leaders
- Using accurate and verified emissions data to support policy development
- Promoting development and deployment of clean technologies
- Considering broad alignment with other emissions reduction programs of similar rigour that provides opportunity for linking in the future
- Considering integration with other provincial environmental policies

A key objective of Ontario's greenhouse gas emissions reduction program is to provide an incentive for emitters to invest in technologies that improve their environmental performance, energy efficiency, and competitiveness in a flexible and cost-effective way. As we collaborate with our industry partners on the design of the program in 2013, we will also explore ways to reduce the barriers and encourage investment in increased energy efficiency, fuel switching, materials substitution and research and development that lead to improved economic and environmental performance.

4.0 Potential Elements of a Greenhouse Gas Emissions Reduction Program

4.1 Timing

It is proposed that Ontario's program would be in place one year prior to federal regulation of greenhouse gases from industry. A one year window provides time for the province to negotiate and finalize an equivalency agreement with the federal government to ensure there is a single regulator for greenhouse gas emissions in the province.

4.2 Scope

Greenhouse Gases

Emitters covered by the program would be responsible for emission reductions of greenhouse gases including carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons and perfluorocarbons from covered emission sources. These gases are consistent with the gases covered under the Kyoto Protocol for the United Nations Framework Convention on Climate Change and the reporting requirements under Ontario's Greenhouse Gas Emissions Reporting regulation.

Covered Industries

The ministry is considering applying the program, at a minimum, to the same industrial sectors to be regulated by the federal government. At this time, this includes fossil fuel-fired electricity generation and large emitters from petroleum refining, chemicals (including fertilizer manufacturing), steel, cement and pulp and paper sectors. It is expected that the federal government could expand its coverage to include other sectors as proposed under its previous greenhouse gas proposal in 2007, *Turning the Corner*. The federal government already has a regulation in place for coal-fired electricity that takes effect in 2015.

Covering a broader scope of large emitters consistent with facilities currently covered under Ontario's Greenhouse Gas Emissions Reporting regulation (O. Reg. 452/09) could also be considered. Having a broader program may help achieve additional reductions by encouraging a wider range of facilities to become more energy efficient.

Emissions associated with transportation and residential heating fuels are not currently part of Ontario's reporting regulation and are not proposed to be included in the greenhouse gas emissions reduction program at this time.

Inclusion of Electricity Sector

Ontario has taken significant action to reduce greenhouse gas emissions from the electricity sector. This includes the phasing-out of coal plants by the end of 2014 and implementing the *Feed-in-Tariff* program under the *Green Energy Act*.

Even with these major initiatives in place, the electricity sector will continue to be a significant contributor to Ontario's total emissions. The federal government has already regulated coal-fired electricity generation and will be considering a regulation for natural gas-fired electricity generation. As the province phases out its use of coal, natural gas-fired electricity generation will be more important. The ministry is considering including emissions from the electricity sector in its program. This will help to ensure we do not lose the gains we have made to reduce emissions in this sector and that future growth in energy demand will be met with clean supply and conservation measures.

Coal Phase-Out

Ontario has committed to be coal-free by 2014. By the end of 2013, the province will have shut down 17 of 19 coal units. By the end of 2014, Ontario will be one of the first places in the world to eliminate coal as a source of electricity production. Eliminating coal-fired electricity generation by the end of 2014 is the equivalent of taking up to seven million cars off the road.

The Green Energy and Green Economy Act, 2009

Under a new four-year framework starting January 1, 2011, Ontario's local distribution companies (LDCs) have been given mandatory electricity conservation targets as part of their license condition from the Ontario Energy Board. The aggregate targets for all LDCs are 1,330 megawatts of provincial peak demand savings and 6,000 gigawatt hours of cumulative energy by the end of 2014.

The Feed-In Tariff program

The Feed-In Tariff (FIT) program provides guaranteed long-term rates for renewable energy. It better positions Ontario to move forward on clean energy sources like wind, solar, bioenergy, and waterpower that will create jobs. Since launching FIT in 2009, the Ontario Power Authority has contracted over 1,700 small and large FIT projects and offered about 20,000 microFIT contracts totalling over 4,700 MW – enough energy to power almost 1.2 million homes. Projects with local participation will help encourage support in host communities and result in significant local economic and employment opportunities.

4.3 Emissions Reduction Targets

Electricity Sector

Emissions from the electricity sector have been declining fairly steadily since 2008. This decline is due to a variety of factors with the most significant being the phase-out of coal-fired electricity generation. Emissions are expected to continue declining over the next few years and then rise again as Ontario's population grows, the economy recovers and nuclear units are temporarily shut down for refurbishment.

The ministry is considering setting an emissions limit aimed at stabilizing emissions from the electricity sector over time. This target would take into account the low emissions expected in the early years of the program, and the expected rise in emissions related to nuclear refurbishment and economic growth.

Industrial Sector

Industrial sector emissions data are currently available for petroleum refining, chemicals, steel, cement, pulp and paper, lime and gypsum, copper and nickel, district energy, waste treatment and disposal, natural gas distribution, automotive assembly, food processing, brick making and institutions for 2010 from Ontario's reporting regulation. The data was collected through the single window application developed jointly with the federal government to streamline requirements and reduce the burden on industry. The complete dataset is available for download from our website. http://www.ene.gov.on.ca/environment/en/category/climate_change/STDPROD_085095.html#2010

To make progress on our targets and achieve absolute emissions reductions, it is proposed the emissions limit for industrial sectors be set at the forecast of total emissions expected at the start of the program, thereafter declining by five per cent over five years. The expected emissions levels at the start of the program will be based on the industrial sectors covered by the program and ongoing emissions forecasting being carried out by the Ministry of the Environment with input from the Ministry of Finance and the Ministry of Economic Development and Innovation.

The proposed reduction target of five per cent over five years is achievable based on historic trends. Emitters can begin to plan projects to reduce their emissions and may be able to use flexible compliance options once the program is in place.

A 2010 study by Canadian Manufacturers and Exporters showed that industries could reduce fuel use 29 per cent with a positive return on investment in the near term using best management practices.[2] In addition, a McKinsey report from 2009 on U.S. energy efficiency shows that energy intensive industries have the potential to reduce annual energy consumption and emissions by roughly 16 per cent by 2020 with low or no costs.[3] And finally, a 2009 report from the Canadian Industry Program for Energy Conservation (CIPEC) noted that the mining, manufacturing and construction sectors achieved a 1.9 percent improvement in energy intensity over the period 1990 to 2007.[4] These studies show there is still significant potential for energy efficiency improvements in the future and that reductions can be achieved.

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[2] Canadian Manufacturers and Exporters: *Advancing Opportunities in Energy Management in Ontario Industrial and Manufacturing Sector*

[3] *Unlocking Energy Efficiency in the U.S. Economy. McKinsey and Co., July 2009*

[4] Canadian Industry Program for Energy Conservation (CIPEC), *2009 Annual Report: Energizing the Bottom Line with Energy Efficiency* (November 2009)

Approaches to Emissions Reductions

There are a variety of approaches that can be used to motivate reductions. These include using:

1. production-based benchmarks,
2. energy benchmarks, and
3. reductions from an historical baseline.

Production-based benchmarks (e.g., tonnes of greenhouse gas allowances/ tonne of product) reward early action and more efficient facilities but the development of benchmarks is time and data intensive. A mix of approaches including historical emissions, energy use and production-based benchmarks will likely be needed. Feedback will help determine the most suitable method for each industrial sector.

As the province seeks equivalency with the federal government, consideration will be given to the federal government's performance standards as they are developed and established,

5.0 Flexible Compliance Options

Over the course of discussions with our stakeholders to date, we heard the need for a program to provide flexible compliance options and a clear signal to allow industries to plan their investments. An Ontario program could include flexibility mechanisms for covered emitters to achieve compliance such as investing in energy efficient technology, trading allowances or buying offsets.

5.1 Cost-Saving Investments

Investment opportunities in energy efficiency exist in almost every sector of the economy. These investments are expected to optimize energy efficiency, maximize competitiveness and productivity and retain and create jobs. The worldwide investment in energy efficiency goods and services is currently estimated at $700 billion USD. According to HSBC Global Research (*Sizing the Carbon Economy*, September 2010), this is projected to triple to $2.2 trillion USD by 2020, creating new business opportunities for Ontario companies.

Industry has identified a number of current technologies that can help achieve greenhouse gas emissions reductions and enhance competitiveness. Cross-cutting technologies include:

- Energy efficiency — continual improvement of efficiency of carbon energy systems while improving productivity
- Renewable energy — expansion of wind, solar power, etc., for industry
- Industrial cogeneration — combined heat and power using biomass, waste heat, and lower carbon fuels
- District heating — waste heat used for industry or community heating
- Oxygen-enhanced combustion — addition of oxygen to reduce fossil fuel use
- Fuel switching — replace / supplement fossil fuels with gaseous fuels, biomass, waste-derived fuels (e.g., post-recycling paper), landfill gas, etc.
- Biofuels and bioproducts — increased use of biomass feedstocks (e.g., bio-coke); advanced gasification systems to convert biomass to fuel
- Advanced industrial carbon capture and storage — sequestration of carbon (e.g., in slag, a by-product of metal smelting)

Some of these technologies will require complementary policies, such as the use of alternative fuels, to enable their implementation.

5.2 Trading

Putting a limit on greenhouse gases emitted by industry will drive the development of new technology and innovations to reduce emissions. The more industry innovates, the more it can potentially benefit financially from the greenhouse gas emissions reduction program.

Many provinces, such as Alberta and Quebec, have already established market-based approaches to greenhouse gas emissions reduction programs and Saskatchewan is also proposing an emissions trading system for electricity generation and industry. Ontario itself has a market-based program to address emissions of nitrogen oxides and sulphur dioxide. The Regional Greenhouse Gas Initiative, an emissions trading system for the electricity sector in nine Northeastern US states, has been in place since 2009.

Flexible mechanisms give industry choices about how to comply with the emissions reduction target. Industry can invest in new technology to reduce their emissions, change to lower carbon fuels or trade with businesses that can reduce their emissions at lower cost. Businesses that undertake projects to reduce emissions can bank allowances for future use or gain revenue by selling surplus allowances to other emitters. Trading helps establish the carbon price which in turn supports investment decisions and provides businesses with choices on how to achieve reductions at the lowest cost.

Efficacy of Emissions Trading

In a report released October 2012, the International Institute for Sustainable Development recommended the use of flexible regulatory approaches to meet greenhouse gas reduction goals. The report demonstrated that the oil and gas sector, for example, could not meet some moderately stringent targets without being able to access emissions reductions made in other sectors of the economy.

Evidence shows that clear policies communicated early, broadly targeting emissions across the key sectors and with flexible compliance mechanisms, achieve reductions at the lowest cost — much lower than traditional emission standards. (NRTEE 2008 and 2009; OECD, 2010; Pembina Institute 2009; Pew Centre 2010.)

Experience from other jurisdictions has shown that trading can bring cost savings compared to conventional regulatory approaches. Studies indicate that the U.S. sulphur dioxide trading program to combat acid rain led to savings of 43-55 per cent compared to using a performance standard approach. Studies also indicate that the flexibility offered by a trading program encouraged innovation by allowing different options for reducing emissions.[5]

5.3 Offsets

A number of economic modelling studies have shown that offsets can be a critical and effective component for achieving low-cost reductions for covered industries.[6] Offsets also help to promote investment and innovation in uncovered sectors of the economy by providing a financial incentive to reduce emissions.

Ontario is proposing to develop protocols that support the creation of high quality offsets in Ontario for use in its greenhouse gas emissions reduction program. As we carry out this work, we will continue to coordinate with the federal government and other jurisdictions, including the Western Climate Initiative and North America 2050, to develop protocols to support Ontario offsets. Protocols will be developed with a view to support the development of a robust offsets market. Protocols under consideration in the short-term will focus on offset activities for which existing protocols can be more easily adapted. These may initially include:

- Nitrous oxide reductions from fertilizer management in agriculture
- Emission reductions from dairy cattle
- Destruction of ozone depleting substances (ODS) from foam insulation
- Destruction of methane from small landfills

[5] Burtraw, Dallas and Szambelan, *U.S. Emissions Trading Markets for SO_2 and NO_X*
[6] Sustainable Prosperity & IISD, November 2011, Policy Brief for the Industry Provincial Offsets Group (IPOG) - *"Regulating Carbon Emissions in Canada Offsets and Canada's Greenhouse Gas Regulations: Reducing costs, improving competitiveness and lowering emissions*

Development of protocols for other offset activities will also be considered.

Offsets

Offsets are low-cost emissions reduction projects undertaken by unregulated industry or sectors such as farms and forests.

Offsets broaden the emissions reductions beyond regulated sectors and help lower the overall cost of compliance for covered industries who can purchase offsets to meet their compliance obligation.

Offset projects may include landfill methane capture, afforestation and other types of projects. The emissions reductions attributable to offset projects are determined by following protocols. Protocols set out procedures and methodologies for creating offsets and ensure that offsets are high quality and based on real reductions.

6.0 Next Steps

Over the next year, the Ministry of the Environment along with the Ministry of Economic Development and Innovation and the Ministry of Energy will be welcoming comments from the interested public, industry stakeholders, non-government organizations and Ontario's First Nation and Métis communities on the elements of the greenhouse gas emissions reduction program and exploring ways to remove barriers to investment. We are seeking input in the following areas:

1. What sectors should be covered under a greenhouse gas emissions reduction program?

2. What emissions threshold should be used for covering facilities in the program?
    a) Ontario's reporting threshold of 25,000 tonnes of greenhouse gases per year
    b) A higher threshold such as the federal reporting threshold of 50,000 tonnes per year

3. What are the barriers to achieving significant reductions?

4. How could a program be designed to encourage investment in cleaner production?

5. How could a program be designed to address competitiveness concerns within and across sectors?

6. How can a program be designed to integrate with Ontario's approach to reducing air contaminants?

7. How can facilities achieve an emissions reduction of five per cent over five years?

8. What is your perspective on the importance of equivalency and ensuring industry is not subject to duplicate regulation?

Comments can be submitted through the Environmental Registry or Regulatory Registry.

Feedback and comments on this discussion paper will be used to inform the development of Ontario's greenhouse gas emissions reduction program.


For more information on climate change, visit the Ministry of the Environment at: Ontario.ca/environment or call 1-800-565-4923

Ontario

RELOCATION & REPLACEMENT MAINS VARIANCE ACCOUNTS

1. As indicated in updated evidence filed at Exhibit A2, Tab 1, Schedules 1 and 3, and Exhibit B2, Tab 1, Schedule 1, EGD has updated its Customized IR plan to allow for the approval of the 2017 and 2018 Allowed Revenue within this proceeding, and is no longer requesting an update or capital refresh for 2017 and 2018 midway through the 2014-2018 Customized IR term. As explained, EGD proposes that the 2017 and 2018 estimated rate base and related Allowed Revenue amounts previously filed as preliminary values at Exhibit F1, Tab1, Schedule 3 are now to be used as final values. Supporting evidence is filed at Exhibits F6 and F7.

2. As indicated in the Updated Capital Budget Overview evidence (Exhibit B2, Tab 1, Schedule 1, at paragraphs 114 to 116), EGD is also proposing two new variance accounts for 2017 and 2018 only, to deal with two specific elements of its capital spending requirements, relocation and miscellaneous replacement mains. As explained in the above-noted evidence, relocations costs are difficult to forecast and are beyond the Company's control because they arise from the activities of third parties. Costs related to replacement mains requirements identified through pipeline inspection activities such as (but not limited to) In Line Inspection ("ILI") and Maximum Operating Pressure ("MOP") programs are not included within the Company's Capital Budgets, although there is an amount included for "Miscellaneous Main Replacements". While Enbridge has indicated that it will take the risk of such costs for 2014 to 2016, the Company believes it appropriate to have variance account protection for such costs during 2017 and 2018.

3. The proposed variance account treatment is the same for both relocation and replacement mains, however, separate accounts named Relocation Mains Variance

Account (“RLMVA”) and Replacement Mains Variance Account (“RPMVA”) will be established where appropriate for each of 2017 and 2018.

4. EGD believes that it is appropriate to use the same financial eligibility thresholds for these new accounts as exist for Z Factors. Therefore, in order for one of the variance accounts to be operative, there must be a variance of at least $1.5 million from the cumulative revenue requirement associated with relocations or replacement mains for the subject year. If this threshold is met, then the total revenue requirement for the year in which the threshold is met is to be recorded and recoverable in the variance account for that year.

5. The Company proposes that the cumulative revenue requirement for each account for each year is to be determined in the following manner.

6. For the RLMVA, the actual capital spend amounts for relocations activities will be tracked by month for each year (2017 and 2018).

7. The amount to be recorded within the 2017 RLMVA will be determined as follows:

   a. If the spending for relocations activities in 2017 is more than the $12.6 million forecast, then EGD will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million (which is the forecast capital cost for relocations in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RLMVA for future recovery by Enbridge.

b. If the spending for relocations activities in 2017 is less than the $12.6 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RLMVA for future credit to ratepayers.

8. The amount to be recorded within the 2018 RLMVA will be determined as follows

a. First, an amount (which may be positive or negative) related to the 2017 capital spending on relocations will be determined. That will be done by taking the difference (positive) or negative between actual capital spending and $12.6 million, and then determining the revenue requirement implications of that amount in 2018.

b. Second, the relevant revenue requirement amount related to 2018 capital spending on relocations will be added to the number determined in (a).

(i) If the spending for relocations activities in 2018 is more than the $12.6 million forecast, then EGD will eliminate the first $12.6 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $12.6 million (which is the forecast capital cost for relocations in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year.

(ii) If the spending for relocations activities in 2018 is less than the \$12.6 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent.

c. If the sum of the amounts calculated under (a) and (b) above is more than \$1.5 million (positive or negative), then that amount will be recorded in the 2018 RLMVA for future recovery.

9. For the RPMVA, the actual spend amounts for miscellaneous mains replacement activities, including those identified through pipeline inspection activities (such as, but not limited to ILI and MOP programs) will be tracked by month for each year.

10. The amount to be recorded within the 2017 RPMVA will be determined as follows:

a. If the spending for miscellaneous main replacement activities in 2017 is more than the \$5.1 million forecast, then EGD will eliminate the first \$5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the \$5.1 million (which is the forecast capital cost for miscellaneous main replacement activities in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, p. 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year and if the resulting revenue requirement amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RPMVA for future recovery by EGD.

b. If the spending for miscellaneous main replacement activities in 2017 is less than the $5.1 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent. If the resulting amount is at least $1.5 million, then the resulting amount will be recorded in the 2017 RPMVA for future credit to ratepayers.

11. The amount to be recorded within the 2018 RPMVA will be determined as follows

a. First, an amount (which may be positive or negative) related to the 2017 capital spending on miscellaneous main replacement activities will be determined. That will be done by taking the difference (positive) or negative between actual capital spending and $5.1 million, and then determining the revenue requirement implications of that amount in 2018.

b. Second, the relevant revenue requirement amount related to 2018 capital spending on relocations will be added to the number determined in (a).

(i) If the spending for miscellaneous main replacement activities in 2018 is more than the $5.1 million forecast, then EGD will eliminate the first $5.1 million to arrive at the remaining capital spend for use within a revenue requirement calculation, to account for the fact that the impact of the $5.1 million (which is the forecast capital cost for miscellaneous main replacement activities in each year from 2016 to 2018) is already included within Allowed Revenues for 2017 and 2018 (see Exhibit B2, Tab 4, Schedule 1, page 4). The revenue requirement for 2017 will be calculated using the remaining capital spending for that year.

(ii) If the spending for miscellaneous main replacement activities in 2018 is less than the $5.1 million forecast, then EGD will determine the revenue requirement that would have resulted had the unspent portion of that amount been spent.

c. If the sum of the amounts calculated under (a) and (b) above is more than $1.5 million (positive or negative), then that amount will be recorded in the 2018 RPMVA for future recovery.

OPEN BILL ACCESS

1. In the EB-2011-0354 proceeding, the Company and interested parties reached a full settlement of issues related to Open Bill Access ("OBA") services for 2013. As part of that proceeding, the Board approved two Settlement Agreements addressing OBA services: the Amended Settlement Agreement dated October 26, 2012 at Issue D11, and the Supplementary Settlement Agreement dated November 9, 2012, at Issue D11 (collectively, the "2013 OBA Settlement") . The 2013 OBA Settlement provided for the continuation of OBA services in 2013 under the terms of the EB-2009-0043 Settlement Agreement (the "2009 OBA Settlement"), subject to updates for 2013 related to the determination of Enbridge's Fees and Costs to be used for the purpose of determining net income amounts to be shared between Enbridge and ratepayers. As evidenced in the 2013 OBA Settlement, the parties also accepted an updated form of OBA Agreement between Enbridge and Billers.

2. The 2013 OBA Settlement required that if Enbridge was to continue OBA services beyond December 31, 2013 it must bring forward an Application to the Board, setting out the terms under which the Company proposes to continue the program. The Company has determined that it wishes to continue OBA services. During Enbridge's Customized IR term, Enbridge proposes to continue the OBA program under substantially the same terms as in 2013, subject to updates to Enbridge's Fees and Costs to be used for the purpose of determining net income amounts to be shared between Enbridge and ratepayers.

3. As noted, the Company requires OEB approval to continue the OBA program in the 2014 Test Year. Enbridge has elected to apply to the Board for such approval separate and apart from this 2014 Customized IR Application.

Witnesses: K. Lakatos-Hayward
S. McGill

4. Enbridge filed its 2014 Open Bill Application, EB-2013-0099, with the Board on May 9, 2013. Under that Application, Enbridge has sought Board approval to continue the OBA program indefinitely, subject to the ratemaking implications of the program being approved such that they coincide with the term of future rate setting periods of the Company.

5. Within this 2014 Customized IR Application, Enbridge requests that the ratemaking implications of its OBA program as described in its EB-2013-0099 Application be approved to continue for 2014 through 2018.

6. In order to continue the OBA program in its present form, Enbridge has applied to the Board for such final and interim Orders and deferral and variance accounts as may be necessary to implement its proposal for OBA services. These deferral and variance accounts are referenced in this Application (within Exhibit D1, Tab 8, Schedule 1) and in the Company's Open Bill Application, EB-2013-0099.

REVIEW OF THE TREATMENT OF SEPARATE CUSTOMER CARE / CIS AGREEMENT

Background & Overview

1. In September 2011, Enbridge Gas Distribution ("Enbridge" or the "Company") presented to the Ontario Energy Board (the "Board") for approval, a Settlement Agreement within the EB-2011-0226 proceeding for the establishment of Enbridge's Customer Care and Customer Information System ("CC/CIS") costs for the period of 2013 through 2018. On September 8, 2011 the Board approved the Settlement Agreement, a copy of which is filed at Exhibit D1, Tab 10, Schedule 2.

2. Enbridge applied for approval of the 2013 rate making treatment and implications of the settlement within its 2013 EB-2011-0354 rate application, which was approved by the Board within the EB-2011-0354 Final Rate Order, Appendix A, page 1 of 1.

3. This Application includes the implementation of the Board-approved CC/CIS Settlement Agreement for 2014, 2015 and 2016. The implementation of the previously-approved EB-2011-0226 Settlement Agreement contributes incremental amounts of approximately \$3.9 million, \$4.6 million and \$4.8 million to Enbridge's 2014, 2015 and 2016 revenue requirement and resulting deficiencies.

4. This evidence has been prepared to explain how Enbridge's budgeted costs for the 2014, 2015 and 2016 fiscal years, including those required for the provision of CC/CIS services, are adjusted to properly reflect the specific amounts in relation to the 2014, 2015 and 2016 rate impacts approved by the Board through the application of the CC/CIS Settlement Agreement. As explained below, these adjustments are necessary because included within the CC/CIS Settlement

Agreement are a number of items related to the revenue requirement impact of the CIS asset where the Board-approved costs or revenue requirement to be recovered are different from what would be the case if those items were subject to standard treatment.

Impact of Approved EB-2011-0226 Settlement Agreement

5. Enbridge has filed a copy of the approved CC/CIS Settlement Agreement at Exhibit D1, Tab 10, Schedule 2. Enbridge has also filed at Exhibit D1, Tab 10, Schedule 3, a required update of the "Template" which shows the annually allowed costs and related annually allowed revenue or amounts to be recovered in rates. As specified in the "Terms of the Settlement" at page 11, the revenue requirement for all CIS and CC services for each particular year within the Settlement, is to be determined by multiplying the forecast number of customers for that year "(which forecast will be set as part of the annual rate setting processes)" by the cost per customer as shown on page 12 of the Settlement Agreement and line 17a of the updated template. In addition, the amount of revenue requirement to be recovered was agreed to and approved to be smoothed into rates which would be determined annually by multiplying the forecast number of customers for that year by the smoothed revenue requirement per customer as shown on page 12 of the agreement and line 24 of the updated Template. Enbridge has updated the forecast number of customers for 2014 and included a placeholder estimate of the number of customers for 2015 and 2016 (which will be updated in each of the 2015 and 2016 rate setting processes) as shown at line 25 of the updated Template. The resulting updated annual customer care costs and Allowed Revenue for 2014, and placeholder estimates of the same for 2015 and 2016, are shown on lines 26 and 27 of the updated Template.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill

As indicated within Exhibit D1, Tab 10, Schedule 2, pages 21 and 22, the definition of “customer” to be used for determining the CC/CIS revenue requirement is that which is used in the Accenture Customer Care Service Agreement (which is different from the definition of “customer” used elsewhere in this Application, because Accenture includes both active and locked customers).

6. The updated Template at Exhibit D1, Tab 10, Schedule 3, shows a required increase in Enbridge’s 2014 rates (compared to 2013) of $3.9 million (Row 27, Column I, 2014 updated revenue of $114.1 million vs. Row 23, Column H, 2013 approved revenue of $110.2 million). The 2014 CC/CIS updated Allowed Revenue amount is calculated by applying the Board-approved cost per “customer” of $54.68 (the agreement, Row 24, Column. I) multiplied by Enbridge’s updated forecast of “customers” for 2014, Row 25, Column I (which is 2,086,534).

7. Due to the distinct features of the CC/CIS Settlement Agreement it is necessary to separately display the approved revenues, costs and resulting revenue requirement specific to CC/CIS from all other regulated utility revenues, costs and their related revenue requirement within the utility. This is necessary to provide assurance that the levels of revenues and costs approved within the CC/CIS Settlement Agreement have been appropriately reflected within Enbridge’s 2014-2016 rate application and rate setting model.

8. The separation of CC/CIS also ensures that the determination and the required rate impact associated with all other remaining Enrbidge revenues and costs are not impacted by and nor do they alter the manner in which the CC/CIS 2014 to 2016 revenue requirement amounts are to be derived.

9. The importance and required separation of the CC/CIS amounts from all other utility related amounts and calculations is better understood and explained when viewing, as an example, the results within Exhibits E3, E4 & E5, Tab 1, Schedule 1, which sets out the Company's revenue deficiency calculations for 2014, 2015, & 2016.

10. The E3 exhibit shows a capital structure which is balanced to the 2014 utility rate base amount exclusive of CIS of $4,384.3 million (Exhibit B3, Tab 1, Schedule 1, Column 1), which is required in order to be able to calculate a utility sufficiency exclusive of CC/CIS, shown as $13.8M at Line 12. The updated allowed CC/CIS revenue deficiency of ($3.9M), is included at Line 13 of the same exhibit. This separate deficiency determination is required because the approved CIS related capital structure (shown in Table 1 provided on page 8 of this exhibit or Exhibit B, Tab 3, Schedule 4, page 1, EB-2011-0226), contains specific provisions in relation to long and medium term debt and equity ratios and long and medium term debt cost and return on equity rates, which are different than such ratios and rates required for all other utility rate base related amounts.

11. Effectively, therefore, a different capital structure is deemed to exist for the CIS asset as compared to all other items included in Enbridge's 2014-2016 rate base. Because of that difference, it would be inappropriate to apply the capital structure debt, preference share and equity ratios and all related cost rates shown and used within Exhibits E3, E4 & E5, Tab 1, Schedule 1, for all other 2014-2016 utility related rate base to the CIS asset, as this would inappropriately affect and alter the approved CIS asset revenue requirements. For example, long and medium term debt and equity ratios within Exhibit E3, Tab 1, Schedule 1, for the rate base and capital structure exclusive of CC/CIS, are forecast at 59.23% and 36% with respective forecast debt cost and return on equity rates at 5.57% and 9.27%. If the

CIS approved rate base amount was included within the overall capital structure, the approved CIS revenue requirements would be altered as different capital structure ratios and rates would be applied to the CIS rate base as compared to the already agreed upon and approved debt and equity ratios of 64.00% and 36.00% and respective debt cost and return on equity rates of 5.35% and 8.39%.

Summary of CC/CIS Adjustment Amounts/Impacts & Separation Display

12. The following list itemizes where each of the required adjustments and amounts are located (for 2014 only as 2015 & 2016 total costs will be determined in future proceedings).
    a) Exhibits B3, B4 & B5 Tab 1, Schedule 1, pg.2, Column 2
    b) Exhibits B3, B4 & B5 Tab 1, Schedule 2, pg.6, Line 13, Column 5
    c) Exhibist B3, B4 & B5 Tab 1, Schedule 2, pg.7, Line 13, Column 6
    d) Exhibits C3, C4 & C5 Tab 1, Schedule 1, pg.1, Line 1, Column 2
    e) Exhibits D3, D4 & D5 Tab 1, Schedule 1, pg.1, Lines 2-3, Column 2
    f) Exhibits E3, E4 & E5 Tab 1, Schedule 1, pg.1, Line 13
    g) Exhibits E3, E4 & E5 Tab 1, Schedule 2, pg.1, Line 22
    h) Exhibits F3, F4 & F5 Tab 1, Schedule 1, pg.1, Line 13
    i) Exhibits F3, F4 & F5 Tab 1, Schedule 2, pg.1, Column 2
    j) Exhibits F3, F4 & F5 Tab 1, Schedule 3, pg.1, Column 2

Explanation of Adjustment or Separate Display Necessity per Exhibit

13. Item a) Exhibits B3, B4 & B5, Tab 1, Schedule 1, page 2, shows the 2014-2016 rate base approved for CC/CIS in Column 2, the calculation of the forecast rate base amount associated with the remainder of Enbridge's 2014-2016 regulated utility activities in Columns 1 and the combined 2014-2016 total rate base in Column 3. The 2014, \$57.8 million CC/CIS approved rate base amount is found in Table 1 on page 7 through the addition of the amounts within Line numbers 8, 12 and 16 (\$53.5M+\$0.8M+\$3.5M = \$57.8M) under the 2014 Column. The 2015 and

2016 approved rate base amounts are derived in the same manner using the 2015 and 2016 column data. This table was reproduced from Exhibit B, Tab 3, Schedule 4, from the EB-2011-0226 evidence which supported the CC/CIS approved agreement reproduced at Exhibit D1, Tab 10, Schedule 2.

14. Items b) & c) Exhibits B3, B4 & B5, Tab 1, Schedule 2, pages 6 & 7, Lines 13 show the adjustments required for the purpose of determining the 2014-2016 other utility rate base exclusive of the amount approved for CIS. As indicated earlier, this segregation is required in order to properly calculate the revenue requirements and related deficiency or rate impacts of Enbridge's other than CIS related elements. As the CIS related approved rate base, revenue requirement and rate deficiency for 2014-2016 are already known, a separate set of other utility related rate base, balanced utility capital structure / deficiency, and income calculations are required to be performed.

15. Item d) Exhibits C3, C4 & C5, Tab 1, Schedule 1, page 1, the adjustments are required for the purpose of determining the 2014-2016 utility revenue exclusive of the separate amount approved for CC/CIS.

16. Item e) Exhibits D3, D4 & D5, Tab 1, Schedule 1, page 1, shows the adjustments required for the purpose of determining the 2014-2016 utility costs exclusive of the separate amounts approved for CC/CIS.

17. Items f) & h) Exhibits E3, E4 & E5, Tab 1, Schedule 1, page 1 and Exhibits F3, F4 & F5, Tab 1, Schedule 1, each show a capital structure balanced to utility rate base amounts exclusive of CC/CIS and other than CIS gross deficiency/(sufficiency) amounts within Lines 1 through 12, a separate CC/CIS related approved deficiency amount at Line 13, and a total deficiency/(sufficiency) amounts at Line 14.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill

18. Item g) Exhibits E3, E4 & E5, Tab 1, Schedule 2, shows the necessary adjustment required to exclude the debt costs associated with and being recovered within the 2014-2016 approved CC/CIS related Allowed Revenue requirement and deficiency amounts. Absent this adjustment, the level of and associated average cost of long term debt within the utility capital structure exclusive of CIS would effectively be accounting for and recovering CIS interest costs twice, once in the CC/CIS deficiency and again in the other than CC/CIS deficiency.

19. Items i) & j) Exhibits F3, F4 & F5, Tab 1, Schedules 2 and 3, Columns 2, displays the amounts required to be shown separately in relation to CC/CIS within 2014-2016, in order that the utility income statement and rate base amounts exclusive of CC/CIS are calculated and usable for the purpose of calculating a utility total other deficiency exclusive of CC/CIS amounts.

Table 1

Uitlity Owned CIS System
10 Year Life
Ontario Utility Capital Structure

CIS system
Original Agreement / Adjusted in 2013 - 2019 to include incrmental Sys Int costs & IDC & Other capital decrease

Line No.		Col. 1 Component %	Col. 2 Indicated Cost Rate %	Col. 3 Return Component %	Col. 4 (4 dec.) Return Component %
1.	Long-term debt	64.00	5.35	3.42	3.4240
2.	Short-term debt	0.00	4.12	0.00	0.0000
3.		64.00		3.42	3.4240
4.	Preference shares	0.00	5.00	0.00	0.0000
5.	Common equity	36.00	8.39	3.02	3.0204
6.		100.00		6.44	6.4444

	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	10 Year Total
	Per CIS - CC Agreement												
7.	Ontario Utility Income	6.67	9.87	-10.79	-10.93	-11.08	-11.23	-11.37	-11.52	-11.67	-11.82		Total
8.	Rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96		2009- 2019
9.	Gross sufficiency / (deficiency)	(0.95)	5.26	(25.89)	(24.91)	(23.95)	(22.98)	(21.99)	(21.04)	(20.07)	(19.10)		-175.62
10.	2009-2012 total				(46.49)								Total 2013- 2019 (129.13)
	$1.9M Additional IDC in service and $0.4 million lower all other CIS project costs in service Sept 09 impact for 2013-2019												
11.	Ontario Utility Income	-0.08	-0.19	-0.14	-0.15	-0.15	-0.15	-0.15	-0.15	-0.16	-0.16	-0.12	Total
12.	Rate base	0.80	1.48	1.32	1.16	1.00	0.84	0.68	0.52	0.36	0.20	0.05	2013-2019
13.	Gross sufficiency / (deficiency)	(0.20)	(0.45)	(0.36)	(0.34)	(0.28)	(0.27)	(0.25)	(0.24)	(0.24)	(0.23)	(0.16)	-1.67
14.	2009-2012 total				(1.35)								
	$6.6M Additional SI costs in service Sept 09 impact for 2013-2019												
15.	Ontario Utility Income	1.05	0.61	-0.59	-0.60	-0.62	-0.63	-0.63	-0.64	-0.65	-0.65	-0.44	Total
16.	Rate base	2.18	6.10	5.44	4.78	4.12	3.46	2.80	2.14	1.48	0.82	0.20	2013-2019
17.	Gross sufficiency / (deficiency)	1.42	0.34	(1.47)	(1.42)	(1.19)	(1.13)	(1.08)	(1.04)	(1.00)	(0.93)	(0.60)	-6.97
18.	2009-2012 total				(1.13)								
19.	CIS with original spend agreement impacts plus additional IDC impact / additional System Integrator cost 2013-2019 COS Revenue Requirements (lines 9 + 13 + 17)					-25.42	-24.38	-23.32	-22.32	-21.31	-20.26	-0.76	Total 2013-2019 -137.77

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill

SETTLEMENT AGREEMENT

Enbridge Gas Distribution Customer Care and Customer Information System costs for 2013 to 2018

September 2, 2011

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PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the "OEB" or the "Board") in connection with the application of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company"), for an order or orders approving a Template setting out Enbridge's customer care ("CC") and Customer Information System ("CIS") costs, and associated component of revenue requirement for the period from 2013 to 2018 (the "Application").

In Procedural Orders No. 1 and 2, the Board established the process to address this Application, as well as the Issues List for this proceeding. The evidence for this application comes from four sources: (i) Enbridge's prefiled evidence; (ii) answers to interrogatories from Board Staff and intervenors; (iii) evidence from a technical conference held August 17, 2011; and (iv) additional evidence provided following the technical conference through undertakings given at and after the technical conference, including information provided during the Settlement Conference and subsequently placed on the public record by agreement between the parties.

A Settlement Conference was held on August 23 to 26, 2011. George Dominy acted as the OEB-appointed facilitator for the Settlement Conference. This Settlement Agreement arises from the Settlement Conference and subsequent discussions.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (BOMA)
CANADIAN MANUFACTURERS & EXPORTERS (CME)
CONSUMERS COUNCIL OF CANADA (CCC)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO (FRPO)
SCHOOL ENERGY COALITION (SEC)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Agreement deals with all of the issues on the Board's "Issues List" that is set out in Procedural Order No. 2. As required by the Board's Procedural Order No. 1, this Settlement Agreement also includes a detailed explanation and justification for the settlement of each issue, including a full discussion of the evidentiary basis upon which the settlement was reached.

All intervenors listed above participated in the Settlement Conference and subsequent discussions. Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Agreement. Enbridge and all intervenors have agreed to the settlement of all of the issues on the Issues List, as described on the following pages. The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B, Tab 3, Schedule 1 is referred to as B-3-

1. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board.

The Settlement Agreement describes the agreements reached on the issues. The Settlement Agreement contains explanation of the evidence supporting and relating to each issue. In addition, the Settlement Agreement provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board wishes further evidentiary support with respect to any of the issues, the parties will have available witnesses from both Enbridge and the intervenors to provide such support through oral evidence.

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the *Ontario Energy Board Rules of Practice and Procedure*. Finally, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings. However, any such position cannot have the effect of changing the result of this Agreement.

It is acknowledged and agreed that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety, there is no Settlement Agreement (unless the parties agree that any portion of the Settlement Agreement that the Board does accept may continue as a valid Settlement Agreement).

BACKGROUND

Through this Application, Enbridge is seeking approval of its annual revenue requirement – cost-based and then smoothed - for CC and CIS services, for the years from 2013 to 2018. The parties are pleased to advise the Board that, through the settlement process and preceding extensive consultation process, agreement on an overall CC/CIS revenue requirement of $735 million for those six years has been achieved, with total annual increases in costs per customer from 2013 to 2018 of 0.6% per year, and amelioration of the jump in cost per customer from 2012 to 2013 through a smoothing mechanism.

Effectively, this Application seeks an amendment, update and extension to a Settlement Agreement approved by the Board in the EB-2006-0034 proceeding, in respect of CC and CIS costs for the 2007 to 2012 period (the "2007 Settlement Agreement").[1] The 2007 Settlement Agreement set out the Company's CC and CIS costs for 2007 to 2012 (organized by category in an attached template), as well as a smoothed annual revenue requirement for the sum of those costs in each year. The extended and expanded Template (the "2013 Template") attached to this Application as Ex. A-2-2 uses the same approach and sets out the Company's forecast CC and CIS costs, and associated annual revenue requirement, for the 2013 to 2018 period.
The 2007 Settlement Agreement was reached after a lengthy, intense and successful consultative process between Enbridge and stakeholders. Throughout that consultative process, Enbridge worked principally with a stakeholder steering committee consisting of representatives from Consumers Council of Canada ("CCC"), Industrial Gas Users Association ("IGUA")[2] and School Energy Coalition ("SEC"), who had been selected by the larger stakeholder community to represent their interests. As described in the letter from counsel to CCC to the Board dated July 25, 2011, the previous consultative process came about after Enbridge's previous failed attempts to get approval for a new CIS resulted in the Board suggesting that the Company and intervenors should try to work cooperatively on a solution that would avoid another lengthy and expensive hearing. The consultative process was also intended to address the disagreements and acrimony resulting from Enbridge's then-current contract to receive CC services from an affiliate (CustomerWorks Limited Partnership).

The consultative's main purpose in the 2007 process was to provide Enbridge with stakeholder feedback and guidance throughout the design, tendering and contracting phases of the CC and CIS initiatives, with the objective of leading to a consensus proposal for review by the Ontario Energy Board (the "OEB" or the "Board"). Ideally, the process would meet the interests of Enbridge and ratepayers in allowing Enbridge to proceed with necessary long-term plans for its customer care operations, including the acquisition of a new computer system to manage billing functions (the new CIS asset).

Ultimately, that 2007 consultative process led to a resolution of most of the regulatory and ratemaking issues related to the procurement of new CC and CIS services and the provision of CC services. This allowed Enbridge, with stakeholder support, to procure a new CIS and to enter

[1] Exhibit N1, Tab 1, Schedule F in the EB-2006-0034 proceeding. Filed in this proceeding as Ex. I-1-33.

[2] The lawyers who had participated in the Steering Committee on behalf of IGUA subsequently (in mid-2007) became the representatives of Canadian Manufacturers & Exporters ("CME") and thereafter participated in the Steering Committee on behalf of CME.

into a contract with Accenture Business Services for Utilities ("Accenture" or "ABSU") for the provision of CC services for a five year term.

A fundamental component of the resolution was the agreement among all parties that the overall CIS and CC costs to be incurred during the then-current year (2007) and the expected five year incentive regulation ("IR" or "IRM") period that would follow (2008-2012) would be summed together and then smoothed over the entire six year period. The six year term of the settlement allowed the Company to proceed to award long term contracts for a new CIS asset and to a new CC service provider. Through the settlement, Enbridge benefitted from several years of budget predictability in this important area, with broad freedom to optimize operational decisions. The ratepayers benefitted from minimal increases in costs, and low, gradual, and controlled rate impacts.

The 2007 Settlement Agreement that was prepared by the consultative group endorsed Enbridge's plans to acquire and operate a new CIS asset, and to enter into new CC arrangements with a third party provider for the years from 2008 to 2012. The 2007 Settlement Agreement reflected the successful transparent, open and collaborative approach undertaken by the Company with ratepayer representatives, which allowed those representatives to assure themselves, their clients, and the other intervenor groups that the costs sought for recovery were reasonable and appropriate. The 2007 Settlement Agreement was approved by the Board during a hearing on March 22, 2007.[3] In approving the 2007 Settlement Agreement, the Board highlighted the approach used by stakeholders to sum together all costs over six years and create a "smoothed" annual revenue requirement, and noted that "we are impressed by the drafting of this agreement and the sophistication of the process by which it was brought about".[4]

After that time, Enbridge continued to work with the stakeholder steering committee (now comprised of representatives of CCC, CME and SEC) and their expert advisor (Five Point Consulting LLC, referred to herein as "Five Point")[5] to discuss and review the implementation of the new CIS asset. That process took place in the months leading up to and following the implementation of the new CIS asset in September 2009. This continued engagement between Enbridge and ratepayer representatives was consistent with commitments made in the 2007 Settlement Agreement to ensure that the consultative group would monitor the procurement and implementation process for the new CIS.[6] This engagement concluded by around March 2010 with a final review and endorsement of the costs associated with Enbridge's new CIS.[7]

Starting around that same time (March 2010), Enbridge and the stakeholder steering committee also worked together on issues related to the procurement of CC services after the date when the current arrangement with Accenture terminates (April 1, 2012). Enbridge believed that the interests of all parties would be best served by having ratepayer representatives informed and

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[3] EB-2006-0034, 15 Tr. 85. Filed in this proceeding as Ex. I-1-34.

[4] EB-2006-0034, 15 Tr. 83-85. Filed in this proceeding as Ex. I-1-34.

[5] Five Point is the corporate successor to TMG Consulting, which was the expert advisor to the stakeholder steering committee in connection with the 2007 Settlement Agreement. For ease of reference, TMG Consulting and Five Point Consulting are both referred to as "Five Point" in this Application.

[6] 2007 Settlement Agreement, at p. 6: see Ex. I-1-33.

[7] Transcript from August 17, 2011 Technical Conference, at pp. 61-62.

involved in this process as it unfolded, rather than by seeking stakeholder endorsement after the fact. The reason why this process began in the winter of 2010, despite the fact that the current Accenture Customer Care Services Agreement ("CCSA") runs until March 31, 2012 is that there is a long lead time associated with the replacement of CC services and with notice provisions under the current CCSA. That long lead time is required to account for any request for proposal ("RFP") process that might be required and to account for the time and effort that would be required if a transition to a new service provider became necessary.[8]

This ongoing process between Enbridge and the stakeholder steering committee led to a number of developments in respect of the Company's CIS and CC arrangements. These developments are directly relevant and impactful to the amounts to be recovered for CIS and CC services in the years after the term of the current 2007 Settlement Agreement concludes (starting as of January 1, 2013). To the extent that these developments impact the actual costs paid by Enbridge for CIS and CC services before January 1, 2013, those impacts will not be included in Enbridge's revenue requirement for 2011 and 2012, since the values in the 2007 Template will continue to apply for the term of the 2007 Settlement Agreement (until December 31, 2012) as originally agreed.

The first development is that the Company's new CIS asset has now been successfully brought into service and all implementation costs associated with the new CIS asset (which has a ten year economic life) are known. These costs were reviewed and endorsed by the stakeholder steering committee as part of their original mandate to review the implementation of that asset. In advance of the filing of this Application, Enbridge and the stakeholder steering committee agreed on the final capital cost of the new CIS asset, and the resulting opening rate base amount for the new CIS asset as of January 1, 2013, when the 2007 Settlement Agreement comes to an end. The new opening rate base amount of $76.9M is modestly higher than the $71.4M amount indicated in the 2007 Settlement Agreement. Enbridge and the stakeholder steering committee also agreed on the revenue requirement that would result from the updated rate base value for the new CIS asset for the years from 2013 to 2018.

The second development is that a process has now been undertaken to proactively evaluate the Company's current CC arrangements, and future options for receiving CC services, in the interest of ensuring the best possible future arrangements for ratepayers and Enbridge. The goal of this process was to determine how best to obtain CC services in the years after April 1, 2012, when the current CCSA with Accenture expires. In consultation with the stakeholder steering committee, Enbridge implemented a multi-stage strategy in which it first sought to avoid the cost and disruption of an RFP by obtaining sufficiently attractive terms from the incumbent Accenture. Failing that, an RFP would be launched and competitive bids obtained.

This process was successful. Enbridge obtained favourable terms from the incumbent, thereby avoiding the substantial costs associated with an RFP and a transition to a new service provider. Enbridge has reached an agreement with Accenture, subject to approval by the Board, for an update and extension of the current CCSA for five years, with an option for two more years. In advance of the filing of this Application, Enbridge and members of the stakeholder steering committee agreed that the terms of the update and extension are reasonable and in the best interest of the Company and its ratepayers. Enbridge has agreed with Accenture to the update and extension of the current CCSA, conditional on receiving OEB approval for the recovery of

[8] Ex. B-4-1, pp. 3-4.

costs that will be charged under that agreement. That approval must be received by September 15, 2011 in order for Enbridge to avoid having to negotiate for a temporary extension of the CCSA.

Having come to a tentative agreement on the prudence of the costs associated with the acquisition and implementation of the new CIS and with the extension of the CCSA, Enbridge and the stakeholder steering committee considered how best to approach obtaining regulatory approvals.

Enbridge and the stakeholder steering committee agreed upon two key items in that regard.

First, Enbridge and members of the stakeholder steering committee agreed that it is better to consider the CIS and CCSA costs agreed upon, not just in isolation, but in the context of Enbridge's broader CIS and CC costs for the 2013 to 2018 period. This provides a more complete context and allows for the Company's forecast ongoing costs to be evaluated on a consistent basis in comparison to current costs (which are set out in the Template filed as Ex. B-5-2). This was the purpose of the Template in the 2007 Settlement Agreement (the "2007 Template"), and it continues to be the most comprehensive way of ensuring a fair result. The way that this was effected was by extending the 2007 Template to include therein the Company's CIS and CC costs for the 2013 to 2018 period, upon which Enbridge and the steering committee have agreed, along with Enbridge's forecasts of other related CIS and CC costs for that time frame.

Enbridge's forecast CIS and CC costs for the 2013 to 2018 term are set out in the extended and expanded "2013 Template" that is included with this Application as Ex. A-2-2. Prior to the filing of the Application, Enbridge and members of the stakeholder steering committee agreed upon the values set out in rows 3 and 10(a) of the 2013 Template, which relate to the revenue requirement for the new CIS asset (line 3) and to the costs of the update and extension of the current CCSA, (line 10a). These lines represented $437M, or approximately 60% of the total costs in the 2013 Template. There was at that time no agreement to the values in the balance of the 2013 Template which represent Enbridge's forecasts of other related CIS and CC costs for that time frame (and which comprised about $321M of the six year costs).

Second, it was agreed that it was important and timely to immediately involve other stakeholders, and the OEB, in any further deliberations around Enbridge's CC and CIS costs. The intention was to first seek to achieve consensus agreement on the two items upon which Enbridge and the stakeholder steering committee had agreed (CIS capital costs and costs associated with the extended CCSA), and then to engage in deliberations related to the balance of Enbridge's CIS and CC costs as set out in the 2013 Template for the 2013 to 2018 period. Enbridge's stated objective was to discuss and negotiate all items in the 2013 Template to seek to reach a comprehensive agreement about Enbridge's CC and CIS costs for the 2013 to 2018 term.

The foregoing is the context for Enbridge's Application, which was filed on June 20, 2011.

One item of note in Enbridge's Application, as seen in the 2013 Template, is the fact that there is a substantial increase of approximately $21.7 million in forecast revenue requirement between 2012 and 2013. Explanation for this increase is set out in evidence at Ex. B-2-1 (para. 8) and Ex. JTC1.10. The main reason for the increase, accounting for approximately $14.4M per year in revenue requirement, relates to the smoothing of CIS revenue requirement. During the 2007 to

2012 period, the average annual CIS revenue requirements, as calculated through the 2007 Template, were relatively low. This is because during that period the Capital Cost Allowance ("CCA") provided tax timing benefits to be recognized through 2012 in relation to the CIS asset's ten year economic life. Under the smoothing approach used in the 2007 Template, all of the CCA timing benefit was spread through the first five years of the economic life of the CIS asset, with the result that the 2012 revenue requirement recovered in rates is, per the 2007 Settlement Agreement, intentionally lower than the actual forecast revenue requirement in that year. As of January 1, 2013, when all of the CCA benefit has been credited to the CIS revenue requirement during previous years, the annual CIS cost to be recovered in the remaining years of the asset's economic life will necessarily increase. Through the 2007 Settlement Agreement, all parties were aware that the annual CIS-related revenue requirement would increase substantially at the end of the term of the Settlement Agreement, and all parties agreed that Enbridge would recover the full revenue requirement associated with the new CIS, throughout its economic life.[9]

As part of the Application, Enbridge indicated the reasons why there is some urgency to the relief sought. This was further explained in a letter dated July 20, 2011 where the Company indicated that:

> The reason [for the urgency] is that Enbridge's current CCSA with Accenture expires on April 1, 2012, and six months' notice must be provided if Enbridge wishes to extend the term of the current CCSA. The extended and updated CCSA that Enbridge has negotiated with Accenture will take effect as of April 1, 2012, but only if OEB approval of the cost consequences of that agreement has been obtained prior to that date. As a result, unless Enbridge receives OEB approval by September 30, 2011, it will have to negotiate another shorter term extension of the current CCSA in order to ensure that customer care services will be in place as of April 1, 2012. Further, if no OEB approval is received by around December 2011, then Enbridge will have to initiate a fresh RFP process for customer care services as of April 1, 2014 (which is the last date provided for in any alternate extension of the current CCSA), because of the lead time associated with such a process. That lead time would cover the RFP process, and any necessary transition to a new service provider. This step will be required even if Board approval of the extension and update of the current CCSA is still under consideration, because Enbridge will have to protect itself and ratepayers against the possibility that Board approval is not ultimately granted.
>
> These timing issues could have substantial financial and other impact on Enbridge and its ratepayers.

In recognition of the urgency of this Application, the Board created an expedited process. That process allowed for parties to review and ask questions about Enbridge's prefiled evidence through Interrogatories and a Technical Conference. Parties also had the opportunity, as part of the Technical Conference, to ask questions of the expert who supported the activities of the stakeholder steering committee (Five Point). This process culminated in a Settlement Conference held in late August 2011, which resulted in agreement on all matters in issue in this Application.

[9] 2007 Settlement Agreement, at p. 13, filed as I-1-33.

TERMS OF THE SETTLEMENT

All parties have agreed upon Enbridge's revenue requirement for CIS and CC services for the period between 2013 and 2018, on a cost per customer basis. This means that for each year from 2013 to 2018, Enbridge's total revenue requirement for all CIS and CC services set out in the Template (which do not include bad debt costs) will be determined by multiplying the cost per customer set out in this Settlement Agreement for each particular year by the forecast number of customers for that year (which forecast will be set as part of the annual ratesetting processes). It should be noted that the customer forecast to be used for this purpose will be different from the other customer forecasts used in annual ratesetting processes, because the customer forecast to be employed for the purpose of setting annual revenue requirement pursuant to the Updated 2013 Template will use the definition of "customer" from the Accenture CCSA which includes both active and locked customers (hereinafter in this Settlement Agreement, the use of the term "Customer" is intended to refer to the definition of "Customer" from the Accenture CCSA).[10] The financial consequences of this Settlement Agreement are set out in an updated version of the 2013 Template (referred to herein as the "Updated 2013 Template"), which is attached to this Settlement Agreement as Appendix "A". The Updated 2013 Template does not include lines 18 to 22, which were in the 2007 Template, because the normalization and true-up process that was used to calculate normalized annual revenue requirements for 2007 to 2012 is no longer applicable.

As noted, this settlement is premised on an agreed cost per Customer for CIS and CC services (exclusive of bad debt costs) for each year over the 2013 to 2018 term. This cost per Customer was derived by: (i) all parties accepting, on a cost per Customer basis, the amounts negotiated between Enbridge and the stakeholder steering committee for the new CIS capital costs (line 3) and the costs associated with the revised and extended Accenture CCSA (line 10a)[11]; (ii) reducing Enbridge's 2013 forecast of all other CIS and CC costs in the 2013 Template (lines 4, 5, 6, 10b, 10c 11 and 12) by $2 per Customer (just under 10%); (iii) summing together the CIS, CCSA and all other CC costs per Customer to create an overall cost per Customer for 2013; and (iv) applying an annual inflation factor of 0.6% to the overall CIS and CC cost per Customer for each year from 2014 to 2018. Using Enbridge's current forecast of Customer numbers for the 2013 to 2018 period, as set out at line 17 of the Updated 2013 Template, the total revenue requirement associated with the agreed upon costs per Customer (as inflated each year) would be $735M. That represents a reduction from the $758M set out in Enbridge's Application (see Ex. A-2-2). It must be noted that the actual revenue requirement to be recovered by Enbridge over the 2013 to 2018 term will be different from $735M. That is because the forecast number of Customers each year will be different (at least to some extent) from Enbridge's current forecast. All parties agree that the reductions to base cost forecasts and the inflation factors used in this Settlement Agreement are not intended to be precedents for other Enbridge proceedings and are without prejudice to the position that any party may take on similar matters in future Enbridge proceedings.

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[10] The definition of "Customer" to be used for this purpose is discussed below in the subsection titled "Annual Revenue Requirement".

[11] As explained below, Enbridge's costs related to Large Volume Billing have been moved from line 10a, where those costs were found in the 2013 Template filed with the Application at Ex. A-2-2, to line 12 (Enbridge backoffice costs) in recognition of the fact that the related services are now provided by Enbridge, and not by Accenture.

The agreed cost per Customer, which is set out at line 17a of the Updated 2013 Template, ranges from $55.75 in 2013 to $57.42 in 2018. The parties have agreed that the cost per Customer amount will be smoothed over the term, to temper the increase in cost per customer from 2012 (the end date of the 2007 Template) to 2013. The smoothed cost per Customer, which is set out at line 24 of the Updated 2013 Template, ranges from $53.50 in 2013 to $59.65 in 2018. For ease of reference, the cost per Customer amounts set out in the Updated 2013 Template are reproduced below:

	2013	*2014*	*2015*	*2016*	*2017*	*2018*
Line 17a Total cost/Customer	**$ 55.75**	**$ 56.08**	**$ 56.41**	**$ 56.74**	**$ 57.08**	**$ 57.42**
Line 24 (Smoothed) Revenue Req't/Customer	**$ 53.50**	**$ 54.68**	**$ 55.88**	**$ 57.11**	**$ 58.36**	**$ 59.65**

All parties have agreed that Enbridge should be given the ability to create a rate smoothing deferral account, which will capture the difference between Enbridge's forecast CIS and CC costs each year versus the smoothed amount forecast to be collected in revenue requirement. In the early years of the 2013 to 2018 term, the balance in that deferral account will grow (because Enbridge's agreed cost per Customer will be higher than the smoothed cost per customer being collected), and then in the later years the balance will decline (because Enbridge's agreed cost per customer will be lower than the smoothed cost per Customer being collected). Enbridge will be entitled to collect interest on balances in the rate smoothing deferral account (at a fixed annual rate of 1.47%), and will clear any amount remaining in the deferral account to or from customers, as the case may be, by normal application to the Board at the end of 2018.

The details of the settlement are set out in the balance of this "Terms of the Settlement" section of the Settlement Agreement. The following sections of the Settlement Agreement set out how the evidence filed supports the settlement, and address how the parties have resolved each of the issues on the Board's Issues List.

A. CIS costs (line 3 of Updated 2013 Template)

All parties agree to a $76.9M opening rate base value for the new CIS asset as of January 1, 2013, based upon the costs associated with the acquisition and implementation of the new CIS. All parties further agree, on a cost per Customer basis, to the revenue requirement to be recovered for the new CIS asset over the 2013 to 2018 term, which totals approximately $137M. That amount is set out at line 3 of the Updated 2013 Template, and is based upon the updated $76.9M opening rate base value for the new CIS asset as of January 1, 2013. That revenue requirement has been converted to a cost per Customer, based on Enbridge's forecast of Customers as set out at line 17 of the Updated 2013 Template. The CIS asset cost per Customer is a component of the overall annual cost per Customer that is set out in line 17a. The context and basis for this agreement is set out in the following paragraphs.

Through the 2007 Settlement Agreement, the parties endorsed Enbridge's acquisition of a new CIS asset. The parties agreed, among other things, to an overall CIS cost of $118.7 million (subject to later adjustments or true-up), including capital, interest during construction ("IDC") and procurement costs. This overall cost was to be recovered over the ten year service life of the new CIS asset. Under the terms of the 2007 Settlement Agreement, the amount included in opening rate base as of January 1, 2013 for the new CIS asset was to be its assumed 2012 closing net book value of approximately $71.4 million. That amount, which is based on the assumed CIS cost of $118.7 million, was subject to adjustment to reflect the actual costs of the new CIS asset.

The 2007 Settlement Agreement's $118.7 million assumed cost for the new CIS asset was based upon a number of things, including: (i) an estimated amount of $42 million for system integrator ("SI") contract costs, which was still in the midst of a direct competitive tender process; (ii) an amount of approximately $76.7 million for all other project costs, which Enbridge was to "manage and control during the CIS procurement and implementation process"; and (iii) an in-service date of January 1, 2009 (used for the estimation of IDC).[12]

The 2007 Settlement Agreement expressly provided for certain aspects of the CIS cost to be adjusted later, by setting a different rate base amount for the new CIS asset as of January 1, 2013, if there were variances from the costs assumed in the 2007 Settlement Agreement. In this regard, the 2007 Settlement Agreement provided that, subject to the restrictions on CIS costs set out therein, all prudently incurred and reasonable costs associated with the new CIS asset, including return and income taxes, should be recoverable in rates, during the 10-year economic life of the new CIS asset.[13]

As contemplated by the 2007 Settlement Agreement[14], the stakeholder steering committee, with the added expertise of Five Point (who acted as expert advisors to the stakeholder steering committee) continued to be engaged with reviewing and monitoring the procurement and implementation of the new CIS asset after the time that the 2007 Settlement Agreement was approved. As of September 2009, the new CIS asset was successfully brought into service. Members of the stakeholder steering committee were provided with information about the implementation of the new CIS asset and the related costs. Five Point worked with the stakeholder steering committee, and Enbridge, throughout the CIS Replacement Project, and issued its Project Close-Out Report on October 29, 2009.[15] The Five Point Project Close-Out Report confirmed the success of the CIS implementation process. As stated by Five Point in its Project Close-Out Report: "The project launch was extremely smooth and can be considered as one of the most successful in the industry … The solution is of very high quality [and] is functioning as designed."[16]

At this time, the new CIS asset is in service, and past its warranty period (which expired in December 2009), and all of the associated capital costs are known. It is now clear that the actual costs of the new CIS asset are different from the assumed CIS cost of $118.7 million that was set out in the 2007 Settlement Agreement. Enbridge and members of the stakeholder steering committee agreed that the additional implementation costs associated with the new CIS asset are reasonable and prudently incurred. The additional costs, which are detailed at Ex. B-3-1[17] total

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[12] 2007 Settlement Agreement, at pp. 11-13, filed as I-1-33.

[13] 2007 Settlement Agreement, at p. 13, filed as I-1-33.

[14] 2007 Settlement Agreement, at p. 6, filed as I-1-33.

[15] A copy of Five Point's Project Close-Out Report is filed as Ex. B-3-2.

[16] Ex. B-3-2, Project Close-Out Report, at slide 3.

[17] At paras. 14 to 17.

approximately $8.5 million. In evidence at the Technical Conference, the Five Point witnesses confirmed that the implementation of the new CIS was successful at a cost that was reasonable and well within industry standards and expectations.[18]

The updated opening rate base value of $76.9 million for the new CIS asset as of January 1, 2013 is approximately $5.5 million higher than the $71.4 million assumed value in the Settlement Agreement. This approach means that approximately $3.0 million of the $8.5 million of additional SI and IDC costs incurred by Enbridge will not be included in the adjusted opening rate base, because that portion relates to amounts that would otherwise have been recovered during the term of the 2007 Template. In other words, Enbridge will not recover that portion of the additional CIS costs which would have been part of revenue requirement during the term of the 2007 Settlement Agreement. That is because the values in line 3 of the 2007 Template that relate to CIS revenue requirement for 2007 to 2012 are not subject to adjustment based upon increased costs. The only adjustment is to the updated rate base value at the end of the term of the 2007 Template, which is what is being addressed in this Settlement Agreement.

Having reached agreement on the opening rate base value for the new CIS asset as of January 1, 2013, Enbridge and members of the stakeholder steering committee then addressed the revenue requirement associated with that determination. Enbridge and members of the stakeholder steering committee agreed that the CIS revenue requirement calculations for 2013 to 2018 would use the same the parameters (including cost of capital) as were used for the calculation of CIS revenue requirement amounts in the 2007 Template. All parties agree that the use of these parameters for the calculation of the line 3 revenue requirement in the Updated 2013 Template (including, for example, the use of an ROE component of 8.39%, which is lower than the ROE that would result from the use of the Board's updated ROE formula) is not intended as a precedent for any future proceedings and is without prejudice to the right of any party to assert that a different approach should be used for the calculation of revenue requirement for capital assets in any future proceedings. To be clear, though, the use of these parameters will continue to apply for the calculation of the CIS revenue requirement in line 3, which is a component of the cost per Customer to be recovered by Enbridge for the years from 2013 to 2018.

Through Enbridge's Application and the settlement process, all parties have now agreed with Enbridge and the stakeholder steering committee that $76.9M is an appropriate opening rate base for the new CIS asset, as of January 1, 2013, and that the revenue requirement set out in line 3 of the Updated 2013 Template is appropriate. The total revenue requirement associated with the new CIS asset over the 2013 to 2018 period is $137M.[19]

In order to convert the amounts agreed upon to a cost per Customer, the annual revenue requirement amounts set out at line 3 were divided by the current forecast number of Customers for each year, as set out at line 17 of the Updated 2013 Template. Those annual costs per Customer for the new CIS asset range from $12.34 in 2013 to $8.93 in 2018.

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[18] Transcript from August 17, 2011 Technical Conference, at pp. 10-12, 30, 34-40 and 42-47.

[19] The calculation of this revenue requirement amount is set out in more detail in Ex. B-3-4.

B. Accenture CCSA costs (line 10a of Updated 2013 Template)

All parties agree, on a cost per Customer basis, to the costs associated with the contracted CC services to be obtained by Enbridge through the revised and extended CCSA with Accenture over the 2013 to 2018 term. Based upon Enbridge's forecast of Customers for the 2013 to 2018 term, all parties agree that a total cost of $300.8M for those services is appropriate. That number, which is set out at line 10a of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018. This amount does not include costs associated with Enbridge's large volume billing ("LVB") activities, which were previously provided by Accenture, but which have now been repatriated to Enbridge. Accordingly, the LVB costs that were included in line 10a of the 2013 Template attached to this Application (as Ex. A-2-2) have been moved to line 12 (Enbridge's backoffice CC costs) in the Updated 2013 Template. The context and basis for the agreement in respect of Accenture CCSA costs is set out in the following paragraphs.

Enbridge currently acquires the majority of its CC services from third party service providers, primarily Accenture. Accenture was chosen as a result of a RFP process run by Enbridge in 2007, which process was explained in the 2007 Settlement Agreement. The members of the stakeholder steering committee were involved in reviewing and commenting upon Enbridge's RFP process that resulted in the selection of Accenture for CC services.

The contracts under which these CC services are purchased (the current CCSA) will reach their normal expiry dates on March 31, 2012. As part of its acquisition of CC services beyond March 31, 2012, Enbridge will either have to execute an agreement with Accenture for the provision of the existing CC service arrangements for a period beyond the scheduled termination of those arrangements (because any transition will take place after that date), enter into service agreements with alternate service providers, repatriate these business functions or trigger extension agreements to extend the existing arrangements with Accenture.

In recognition of the long lead times required to establish CC services, and in recognition of the magnitude and scope of those CC services that Enbridge currently acquires from Accenture, Enbridge embarked upon an initiative in early 2010 to assess its current customer care delivery arrangements and formulate a strategy to meet its CC requirements beyond March 2012. As part of the service delivery review, Enbridge canvassed internal business stakeholders and undertook an external review of industry trends and best practices with respect to CC service delivery strategy. Through this process Enbridge gained information as to current trends in business process outsourcing in the North American utility sector. Additionally, Enbridge determined that EquaTerra Inc. ("EquaTerra") was best suited to assist the Company in a more detailed comparison of Enbridge's CC operations to current industry best practices. EquaTerra was engaged by Enbridge to review the current CCSA and provide perspectives on how Enbridge's outsourced CC services compared to current market standards in terms of cost, service levels and other contract terms. EquaTerra's report to Enbridge concluded that in general there are no major structural defects or omissions in the Enbridge / Accenture CCSA. EquaTerra also found that the current CCSA applies a price per customer model, which is a preferred market methodology for utilities and that comparative market analysis revealed that the Normalized Base Price lies within market comparable market ranges.

Enbridge formalized its CC strategy after receiving the EquaTerra Study. The resulting Enbridge CC strategy took into account the current positive experience with Accenture, the findings of EquaTerra and the notice requirements under the current CCSA, as well as the lead time required to conduct a market tender for the CC services procured under the CCSA and the time required to transition such services to a new vendor if required. A copy of the Enbridge CC Strategy, which appends the EquaTerra Study, is filed as Ex. B-4-3.

At or around that time, Enbridge involved the stakeholder steering committee, to make them aware of the ongoing process and to get their comments and suggestions. Five Point assisted the stakeholder steering committee in that process. The stakeholder steering committee agreed to review Enbridge's progress, and provide a stakeholder perspective on any decisions proposed by Enbridge. To assist in these activities, Enbridge and the members of the stakeholder steering committee agreed upon a Statement of Principles to guide their efforts. A copy of the Statement of Principles is filed as Ex. B-4-4.

Enbridge issued a sole source request for proposal to Accenture in July 2010 to provide the Company with a proposal to extend the CCSA beyond March 2012, addressing Enbridge's revised requirements as documented in its CC strategy (see Ex. B-4-3). In the event that Accenture's extension proposal was not acceptable, Enbridge's approach was to proceed with a full market RFP process in late 2010 (the option with the longest lead time and greatest expense), while assessing the option to repatriate. Enbridge's rationale to consider extension of the contract with ABSU as the primary option was based on two major factors: (i) the total cost associated with conducting a full–blown RFP is in the order of $5-$10 million, with no guarantees that the net cost resulting from the RFP would be lower; and (ii) if a new service provider was chosen transition costs were estimated to be on the order of $20 million and, there are operational risks in transitioning services to either another third party or to repatriate the services back to Enbridge.

As contemplated by the CC Strategy, from July through December 2010 Enbridge was engaged in negotiations with Accenture for the revision and extension of the CCSA. Ultimately, Enbridge and Accenture were able to agree upon a revised and extended CCSA that would run from January 1, 2011 to December 31, 2017, along with an Enbridge extension option for 2018 and 2019. Through the negotiation process, with substantial input from the stakeholder steering committee, Enbridge was able to reduce the total contract amount from Accenture's original $457M proposal to a final amount of $430M. The revised and extended CCSA that Enbridge negotiated adopts recommendations from EquaTerra about contractual terms and conditions, contains enhanced service levels (and adopts suggestions made by Five Points to achieve savings) and is priced at a competitive level. Essentially, the extended and updated CCSA provides for enhanced service levels at a per-customer price that is comparable (over a lengthy term) to current pricing. As a result of this successful outcome, the costs and risks of full market RFP were successfully avoided. The revised and extended CCSA that Enbridge has negotiated with Accenture will take effect as of April 1, 2012, as long as OEB approval of the cost consequences of that agreement has been obtained prior to that date.[20]

Review and comment on the terms, conditions and pricing of the revised and extended CCSA can be found in the Five Point report that is included as Ex. B-4-2, and in the evidence and

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[20] However, as described above, Enbridge must have OEB approval by mid-September in order to avoid having to negotiate a short-term extension of the current CCSA.

undertaking responses from Five Point from the Technical Conference. As seen in those documents, Five Point endorsed the approach that Enbridge followed to negotiate a revised and extended CCSA, and found that the price was a reasonable one, in the circumstances and in comparison with market comparables. Five Point also explained how stakeholder involvement in the procurement process assisted in leading Enbridge to negotiate an overall contract value that was more than $27M less than Accenture's first offer. In its final report to the stakeholder steering committee, Five Point commented that:

- Enbridge's approach was "appropriately timed and logically sequenced" in terms of looking to negotiate with Accenture to extend the agreement before pursuing other options.[21]
- Enbridge was transparent and cooperative in dealings with Five Point.[22]
- Enbridge was successful in striking a contract extension with ABSU for almost the same price as the current CCSA agreement, but with many improvement items incorporated in the new contract.[23]
- The year-over-year increase in annual price through the course of the 7-year contract is within the market norms.[24]

The total cost associated with the revised and extended Accenture contact (the CCSA) is approximately $430M, from January 1, 2011 to December 31, 2017. For a number of reasons, that total cost does not align with the $300.8M amount included in the Updated 2013 Template at row 10a for Accenture CCSA costs. The first reason for the difference is that the Updated 2013 Template does not include costs for 2011 and 2012 under the revised and extended CCSA (since the costs for those years are included in the 2007 Template and already-approved smoothed revenue requirements for 2011 and 2012).[25] The second reason for the difference is that the 2013 Template includes costs for 2018, which are based on the extension option in the revised and extended CCSA (and which are not included in the $430M amount). The third reason for the difference is that the $430M amount includes costs associated with the provision of LVB services, which costs total $17.8M from 2013 to 2018. Given that the Company has now repatriated those services, the LVB costs that were included in line 10a of the 2013 Template attached to this Application (as Ex. A-2-2) have been moved to line 12 in the Updated 2013 Template. The final reason why the $430M total cost of the ABSU CCSA is different from the $300.8M amount in line 10a is that the total ABSU CCSA cost amount includes costs associated with open bill access services and agent billing and collection ("ABC") services which are not included in line 10a of the Updated 2013 Template. The responses to Ex. JTC1.14 and JTC1.5 set out the numbers associated with the derivation of the $300.8M amount included in row 10a of the Updated 2013 Template.

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[21] Ex. B-3-2, Project Close-Out Report, at slides 6 and 7.

[22] Ex. B-3-2, Project Close-Out Report, at slide 28.

[23] Ex. B-3-2, Project Close-Out Report, at slide 28.

[24] Ex. B-3-2, Project Close-Out Report, at slide 28.

[25] As the Company's CC costs for 2011 and 2012 are already addressed in the 2007 Settlement Agreement and the 2007 Template, Enbridge is not seeking any approval of the 2011 and 2012 costs associated with the revised and extended CCSA.

All parties agree that a total cost of $300.8M for the CC services to be obtained through the revised and extended CCSA with Accenture from 2013 to 2018 is appropriate. That number, which is set out at line 10a of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018, using the Company's current forecast of Customers at line 17. Those annual costs per Customer range from $22.34 in 2013 to $24.13 in 2018.

C. All other CIS and CC costs in the Updated 2013 Template

All parties agree, on a cost per Customer basis, to the "other CIS and CC costs" (that is, all the costs in the Updated 2013 Template other than those set out in lines 3 and 10a) set out in the Updated 2013 Template. Based upon Enbridge's forecast of Customers for the 2013 to 2018 term, all parties agree that a total cost of $297.2M for the items set out in lines 4, 5, 6, 10b, 10c, 11 and 12[26] of the Updated 2013 Template is appropriate. That total cost amount, which is the sum of the annual amounts from lines 4, 5, 6, 10b, 10c, 11 and 12 of the Updated 2013 Template, has been converted into an annual cost per Customer amount for each year from 2013 to 2018. The context and basis for the agreement in respect of the "other CIS and CC costs" is set out in the following paragraphs.

As explained above, after Enbridge and the stakeholder steering committee agreed upon 2013 to 2018 costs for the new CIS (line 3) and the revised and extended CCSA with Accenture (line 10a), they turned their attention to Enbridge's other CIS and CC costs for that period. Those parties agreed that it made sense to look at and try to resolve those other costs at this time (rather than at the time of rebasing) for several reasons. First, this approach worked well in the 2007 Settlement Agreement – it has allowed both Enbridge and ratepayers to benefit from stable and pre-set revenue requirements for a large portion of the utility's costs. Second, this approach provides a more complete context to evaluate the impact of the forecast CIS and CCSA costs for 2013 to 2018, in conjunction with all related CIS and CC costs. Finally, this approach ensures that neither Enbridge nor ratepayers are later disadvantaged by having the related CIS and CC costs set at a different time from the CCSA and CIS asset costs.

Accordingly, Enbridge and members of the stakeholder steering committee agreed that it was appropriate to examine Enbridge's other forecast CIS and CC costs for the 2013 to 2018 period. This was done by expanding the 2007 Template that was attached to the 2007 Settlement Agreement to include therein the Company's CIS and CC costs for the 2013 to 2018 period, upon which Enbridge and the steering committee had agreed, along with Enbridge's forecasts of all of its other CIS and CC costs for that time frame.

Enbridge and members of the steering committee did not negotiate on these other CIS and CC costs, as they all wished to broaden their discussions to include all stakeholders. Accordingly, Enbridge proceeded with this Application in which it explained the nature and rationale for all such costs, and sought to negotiate an appropriate resolution with all stakeholders, for presentment to the Board.

[26] This line includes costs associated with Enbridge's LVB activities, which were previously provided by Accenture, but which have now been repatriated to Enbridge.

Enbridge's evidence addresses the nature and amounts forecast for each of the lines in the 2013 Template that contain "other CIS and CC costs for 2013 to 2018. The line items at issue and the nature of the costs in each line are as follows[27]:

Line No.	Title	Description
4	New CIS Hosting and Support	Costs incurred to host and operate the new Enbridge CIS. Approximately 50% of these costs are for direct labour and the remaining 50% for amounts paid to external parties for equipment maintenance etc. These amounts do not include any associated overhead costs (HR, benefits, IT, facilities etc).
5	CIS Backoffice (EGD Staffing)	Costs incurred to perform application support for the new Enbridge CIS. Principally, these costs pertain to Enbridge direct labour. These amounts do not include any associated overhead costs (HR, benefits, IT, facilities etc).
6	SAP Licence Fees	Annual fees payable by Enbridge to SAP in respect of the SAP software licence required for the operation of the new Enbridge CIS.
10b	MET	Annual fees payable by Enbridge to MET in respect of meter reading services.
10c	Postage	Annual cost of Canada Post charges incurred by Enbridge for the delivery of monthly customer invoices and other customer correspondence.
11	Customer Care Licences	The annual cost for software licence for smaller software applications required.
12	Customer Care Backoffice (EGD staffing)	The annual cost incurred by Enbridge to manage and administer the Customer Care business function. This cost is primarily in respect of wages paid to personnel performing this function; and consulting resources to manage the Customer Care business. It also includes costs associated with the repatriated LVB CC function.

The 2013 Template included with the Application set out Enbridge's forecast costs in each of these lines from 2013 to 2018 (see Ex. A-2-2). Those forecast costs were developed by starting with actual 2010 costs which were then inflated using annual inflators that were deemed appropriate for each line. The inflators used were known third party amounts (as for MET and postage costs), CPI and wage inflation, as explained at Ex. I-1-2. Through the discovery process in this case, Enbridge provided additional information about the nature of the other CIS and CC costs and about the manner in which forecasts of those costs for future years were derived.

In order to achieve an overall settlement, all parties have agreed to treat Enbridge's other CIS and CC costs together for the purpose of determining appropriate amounts for 2013 to 2018. This means that the same inflator is to be applied to all costs, even if the underlying cost/inflation drivers are different. Without prejudice to the position that any party might take in future Enbridge proceedings, all parties believe that the use of this approach in this case to address Enbridge's

[27] See Ex. I-2-1.

"other CIS and CC costs" for a six year term is appropriately consistent with IRM-type ratemaking approaches.

Using this approach, and in order to achieve an overall settlement, all parties have agreed that it is appropriate to express Enbridge's forecast "other CIS and CC costs" (lines 4, 5, 6, 10b, 10c, 11 and 12) for 2013 (as set out in the 2013 Template filed as Ex. A-2-2) on a cost per Customer basis for 2013. On a cost per Customer basis, Enbridge's forecast of these costs for 2013 (taken from Ex. A-2-2) is $23.07. For the purposes of reaching an overall settlement, and in order to set a base cost per Customer for 2013, all parties agree that Enbridge's forecast cost per Customer for the "other CIS and CC costs" will be reduced by $2.00. The result is a 2013 cost per Customer of $21.07 for the "other CIS and CC costs" set out in the Updated 2013 Template, based upon Enbridge's forecast number of Customers. That cost per Customer is then inflated each year from 2014 to 2018, as described below, in order to determine future year costs per Customer.

D. Total cost per Customer in the Updated 2013 Template

Taking all of the above together, the parties have agreed on a total 2013 cost per Customer of $55.75 for all 2013 costs in the Updated 2013 Template derived as follows:

		2013
CIS Line 3 only cost/Customer	$	12.34
Line 10a only cost/Customer	$	22.34
All other cost/Customer	$	21.07
Line 17a Total cost/Customer	**$**	**55.75**

This cost per Customer represents Enbridge's base costs for the items set out in the Updated 2013 Template for the 2013 to 2018 period. That base cost per Customer is approximately 3.5% less than Enbridge's forecast costs as set out in this Application (as seen in the 2013 Template filed as Ex. A-2-2).

In order to create future year costs per Customer, all parties agree that the 2013 base cost per Customer will be inflated by 0.6% for each year from 2014 to 2018. All parties agree that the inflator used for the purpose of creating costs per Customer for 2014 to 2018 is a compromise number that creates reasonable results in this case, but also agree that it will not be relied upon as a precedent or indicator of an appropriate inflator of costs or rates in any other Enbridge proceeding. The evidence filed in this proceeding establishes that the inflation factors that might be relevant, whether they are the factors used in Enbridge's current IRM mechanism or are CPI or wage inflation, are higher than the 0.6% inflator used here.

The result of the approach described above is that the agreed-upon cost per Customer for all of Enbridge's CIS and CC costs set out in the Updated 2013 Template ranges from $55.75 in 2013 to $57.42 in 2018. These amounts include costs per Customer for the new CIS asset based on the amounts in line 3 and costs per Customer for the revised and extended CCSA with Accenture based on the amounts set out in line 10a. Implicit in that approach is a cost per Customer for other CIS and CC costs (exclusive of lines 3 and 10a) that ranges from $21.07 in 2013 to $24.36

in 2018. The total annual cost per Customer is set out in the Updated 2013 Template, in line 17a, which is titled “Total cost/customer”.

Over the term of the 2013 Template, the results of the approach used for the purposes of reaching an overall settlement of all costs set out in the Updated 2013 Template are as follows:

	2013	2014	2015	2016	2017	2018
CIS Line 3 only cost/Customer	$ 12.34	$ 11.61	$ 10.89	$ 10.21	$ 9.56	$ 8.93
Line 10a only cost/Customer	$ 22.34	$ 22.74	$ 23.04	$ 23.22	$ 23.40	$ 24.13
All other cost/Customer	$ 21.07	$ 21.74	$ 22.49	$ 23.32	$ 24.12	$ 24.36
Total cost/Customer	**$ 55.75**	**$ 56.08**	**$ 56.41**	**$ 56.74**	**$ 57.08**	**$ 57.42**

For the purposes of creating the Updated 2013 Template, Enbridge has included the agreed-upon values in lines 3 and 10a. The values in the lines that comprise Enbridge’s “other CIS and CC costs” are determined by: (i) multiplying the agreed-upon cost per Customer for the relevant year by the forecast number of Customers for that year to get a total cost for the year; (ii) subtracting the amounts in lines 3 and 10a for that year; (iii) allocating the remaining amount among lines 4, 5, 6, 10b, 10c, 11 and 12 in a manner that replicates the originally-filed 2013 Template, so that proportionate reductions are applied to each line. All parties agree that the individual cost amounts set out in the individual lines of the Updated 2013 Template are illustrative only. As set out below, it is the overall cost per Customer on an annual basis that will be used to determine annual costs and revenue requirement. That is because the number of Customers each year is likely to vary from the forecast set out in line 17 of the Updated 2013 Template.

E. Annual revenue requirement

All parties agree that it is reasonable and appropriate for Enbridge to recover the agreed-upon total cost per Customer in each year of this agreement (from 2013 to 2018). At a high level, this is to be done by multiplying the agreed cost per Customer for any particular year by the most current forecast number of Customers for that year, to arrive at an overall revenue requirement for that year for all costs set out in the Updated 2013 Template. All parties agree that the annual revenue requirement that is determined through the process described herein will be recovered as a pass-through cost in Enbridge’s rates (whether those rates are set through an IRM mechanism or cost of service). That is the same approach as was adopted in the 2007 Settlement Agreement, and Enbridge’s current IRM mechanism, whereby the agreed-upon annual CIS and CC revenue requirement set through the 2007 Settlement Agreement has been treated as a Y-factor in Enbridge’s annual rate adjustment applications.

All parties agree that while the cost per Customer set out in this Settlement Agreement (and in line 17a of the Updated 2013 Template) is fixed and will not change over time, the Customer forecast that is used each year to set the revenue requirement will be updated as part of the rate-setting process for the relevant year. Therefore, in order to set an annual revenue requirement for a particular year, it will be necessary to determine the appropriate number of Customers for that year, using the definition of “Customer” set out below. That will be done as part of the rate-setting process for each year, regardless of the ratemaking regime that applies to Enbridge in any year. Enbridge’s Customer forecast set out in line 17 of the Updated 2013 Template was prepared using the definition of “Customer” in the Accenture CCSA, since that definition is what is used to determine Accenture’s costs. As described above, it is the line 17 forecast of Customers that was used to determine forecast costs in the 2013 Template (that was also the case in respect of the 2007 Template). Therefore, in order to be consistent, the annual forecast of Customer numbers that will be used to determine annual CIS and CC revenue requirements in each year from 2013 to 2018 will also apply the definition of Customer from the Accenture CCSA.[28] That definition provides that "the term Customer shall mean: a person actively receiving gas distribution and/or natural gas commodity service from EGD; or a person that has had gas distribution and/or natural gas commodity service from EGD terminated for non-payment, which account is subject to Collection Services under this Agreement.". In other words, the annual forecast of Customers will include both active and locked customers.

It should be noted that the approach to determining annual CIS and CC revenue requirement for the years from 2013 to 2018 is different from the approach adopted in the 2007 Settlement Agreement. The difference arises from the fact that the settlement in this case is premised on a fixed annual cost per Customer to be recovered, rather than upon a fixed annual revenue requirement to be recovered. What that means is that while the cost per Customer to be recovered each year is being set through this Settlement Agreement, the annual revenue requirement to be recovered under the terms of this Settlement Agreement will not be set until the rate-setting proceeding for each relevant year, when the forecast number of Customers for that year is known.

F. Smoothing

The annual revenue requirement determination process set out in the paragraphs above would apply if the cost per Customer agreed upon was simply applied each year without modification. Intervenors have indentified, however, that this approach would result in a 2013 increase (versus 2012) in revenue requirement (and cost per Customer) that is relatively higher than ratepayers would prefer. Therefore, for the purposes of settlement, the parties have agreed upon a different pattern of recovery which lessens the impact of increased revenue requirement in 2013 and provides rate stability over the 2013 to 2018 time period. This is effected by creating a lower cost per Customer for 2013 and then increasing that cost per Customer over the remainder of the term in a manner that will allow Enbridge the opportunity to recover the full agreed-upon revenue requirement of $735M (assuming that the Customer forecast in line 17 is accurate).

The total cost per Customer (without smoothing) for 2013 agreed upon in the Updated 2013 Template is $55.75. While that amount is lower than Enbridge's forecast 2012 cost per Customer of $57.37[29], it is higher than the smoothed cost per Customer of $49.06 that will be collected by Enbridge in rates for 2012, using the "smoothed" revenue requirement set out at line 23 of the 2007 Template and Enbridge's current forecast of customers for 2012.[30] In order to temper the

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[28] Found in the Overview section of Schedule 3.1 to the CCSA ("Service Fees") – see Ex. I-1-12.

[29] As set out in the version of the 2013 Template filed as Ex. B-5-2.

[30] To be clear, this 2012 cost per Customer was calculated as follows: the 2012 "smoothed" revenue requirement set out in line 23 of the 2007 Template (which number is also set out in the Updated 2013 Template) was divided by Enbridge's current forecast of Customers for 2012, which is set out at line 17 of Ex. B-5-2. .

cost per Customer (and corresponding rate) increase from 2012 to 2013[31], all parties have agreed to reduce the 2013 cost per Customer from $55.75 to $53.50. That represents a 9.1% increase from the forecast 2012 cost per Customer ($49.06) that will be collected in rates for 2012. Then, in order to ensure that Enbridge can recover the total agreed-upon revenue requirement of $735M (based on current Customer forecasts), the smoothed 2013 cost per Customer of $53.50 will be increased by 2.2% per year, ultimately leading to a 2018 cost per Customer to be recovered in rates of $59.65. The result is that the cost per Customer to be recovered in rates for 2018 will be higher than Enbridge's actual agreed upon cost per Customer of $57.42 per year. The fact that Enbridge's recovery per Customer will be higher than its costs over the later years of the Updated 2013 Template will offset the fact that Enbridge will recover an amount less than its costs in the early years.

The cost per Customer that Enbridge will recover in revenue requirement is set out at line 24 of the Updated 2013 Template. For convenience, it is also reproduced below:

	2013	*2014*	*2015*	*2016*	*2017*	*2018*
Line 24 Revenue Requirement/Customer	**$ 53.50**	**$ 54.68**	**$ 55.88**	**$ 57.11**	**$ 58.36**	**$ 59.65**

As explained above, as part of the ratesetting process for each year from 2013 to 2018, the annual cost per Customer at line 24 will be multiplied by the updated Customer forecast for that year (using the definition of "Customer" from the Accenture CCSA, as set out above) to derive the total revenue requirement for all services included in the Updated 2013 Template for that year. The total revenue requirement that is determined will be recovered as a pass-through cost in Enbridge's rates (whether those rates are set through an IRM mechanism or cost of service).

G. Deferral account

The smoothing of the CIS and CC revenue requirement will result in Enbridge recovering less than its allowed costs over the early years of the Updated 2013 Template. Parties agree that Enbridge should be allowed to create a deferral account to track its forecast recovery of revenue requirement for the CIS and CC services set out in the Updated 2013 Template versus its forecast allowed costs for those services, and to charge interest on that account. Parties agree that, in principle, this is similar to the approach taken for electricity distributors, where rate mitigation is accomplished by spreading anticipated rate increases over several years while tracking annual under-recovery and associated interest. Since smoothing is a type of rate mitigation, all parties believe it is appropriate to use a similar approach.

The details of the agreed-upon deferral account approach are as follows.

- Enbridge will create a rate smoothing deferral account for each year from 2013 to 2018 which will capture the difference between Enbridge's forecast CIS and CC costs each year versus the amount to be collected in revenue requirement. The costs to be used in this regard will be

[31] The primary reason for this increase in smoothed cost per customer, as explained above in the "Background" section, is that ratepayers will receive the full CCA (depreciation) benefit from the new CIS during the term of the 2007 Template and none of that benefit will be available to offset revenue requirement as of 2013. This outcome was anticipated and understood by all parties at the time of the 2007 Settlement Agreement.

the "Total cost/customer" amount set out for each year in line 17a of the Updated 2013 Template, multiplied by the forecast number of Customers (using the definition from the CCSA) for that year. The revenue requirement amount to be used will be the "smoothed" cost per Customer set out for each year in line 24 of the Updated 2013 Template, multiplied by the forecast number of Customers (using the definition from the CCSA) for that year. For simplicity, Enbridge will calculate the amount to be credited or debited to the deferral account each year by multiplying the difference in cost per Customer and smoothed cost per Customer, times the updated Customer forecast for the year. For example, in 2013 the debit to the deferral account will be ($55.75 less $53.50) times the updated Customer forecast. In the early years of the 2013 to 2018 term, the balance in the rate smoothing deferral account will grow (because Enbridge's cost per Customer will be higher than the smoothed cost per Customer being collected), and then in the later years the balance will decline (because Enbridge's cost per Customer will be lower than the smoothed cost per Customer being collected).

- Enbridge will be entitled to collect interest on balances in the rate smoothing deferral account (at a fixed annual rate of 1.47%, which is the current Board-approved rate, and will not change during the period the deferral account continues). Interest amounts will be cleared annually to customers, at the same time as Enbridge's other deferral and variance accounts are cleared.

- The principal balance in the rate smoothing deferral account will not be cleared during the 2013 to 2018 term. Instead, the principal balance will build up during the years from 2013 to 2015 (when Enbridge's cost per Customer will be higher than the smoothed cost per Customer) and then the balance will be drawn down over the years from 2016 to 2018 (when Enbridge's cost per Customer will be lower than the smoothed cost per Customer). In the event that there is any balance remaining in the rate smoothing deferral account at the end of 2018, that balance (whether it is positive or negative) will be cleared to customers along with the clearance of other 2018 deferral and variance accounts.

H. Bill impacts from Settlement Agreement

For the purposes of this proceeding, all parties agree that it is not necessary to address any issues about the allocation of the costs set out in the Updated 2013 Template to rate classes on the basis of customer numbers. The parties agree that the appropriateness of this or any other cost allocation between rate classes is most appropriately addressed as part of Enbridge's rate applications for 2013 and beyond. For the purposes of determining bill impacts from this Settlement Agreement, all parties agree that it is appropriate to use the cost allocation methodology that applies to the 2007 Template, which allocates the "smoothed" CIS and CC revenue requirement to rate classes on the basis of Customer numbers. That agreement is without prejudice to the right of any party to address the issue of rate class allocation of these costs as part of Enbridge's rate applications for 2013 and beyond.

All parties agree that the bill impacts arising from the Settlement Agreement are reasonable and appropriate.

On an absolute basis, based on Enbridge's current forecast number of Customers for 2012 and 2013[32], the increase on customer bills arising from this Settlement Agreement will be $4.44 per customer from 2012 to 2013 (equal to a 9.1% year-over-year change in the customer care component of customer bills), and then approximately $1.20 per year (2.2%) for each year from 2014 to 2018.[33]

In terms of overall bill impact, the increase from 2012 to 2013 is equal to approximately 0.5% for a typical sales customer, and approximately 0.8% for a typical T-service customer. Then, the average bill impact for each year from 2014 to 2018 is equal to approximately 0.1% for a typical sales customer, and approximately 0.2% for a typical T-service customer. For ease of reference, the bill impacts arising from the use of the "smoothed" cost per Customer agreed upon in this Settlement Agreement are set out in the table below.

	2012	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*
Smoothed cost/Customer - line 24	$ 49.06	$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65
Year over year % increase		9.1%	2.2%	2.2%	2.2%	2.2%	2.2%
Sales customer bill impact		0.5%	0.1%	0.1%	0.1%	0.1%	0.1%
T-Service customer bill impact		0.8%	0.2%	0.2%	0.2%	0.2%	0.2%

I. Other items

One of the Board's issues (Issue 19) asks whether any of the costs included in the 2013 Template should be considered to be "Non-Utility Costs". All parties agree that this proceeding is not the appropriate time for considering that question, as the scope of the Company's activities for the 2013 to 2018 period, including open billing activities, is not currently settled. Instead, the issue of how any costs included within the Updated 2013 Template that relate to activities such as open bill access and agent billing and collection should be treated is appropriately raised in Enbridge's rate applications for 2013 and beyond. Therefore, all parties agree that the settlement of an appropriate cost per Customer for all CIS and CC activities set out in the Updated 2013 Template is without prejudice to the position that any party may take in Enbridge's rate applications for relevant years as to how some of those costs should be eliminated or allocated in respect of non-utility activities and open bill access.

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[32] Enbridge's current Customer forecast numbers for 2012 are set out in the version of the 2013 Template filed as Ex. B-5-2. The Updated 2013 Template includes Enbridge's current Customer forecast for 2013 to 2018, as had been set out in the 2013 Template filed as Ex. A-2-2.

[33] It should be noted that the actual per customer bill impact for Enbridge's customers will likely be slightly different from what is shown in this paragraph. That difference arises from the fact that the absolute amount of bill increase and percentage increase for each customer as set out above is calculated based upon Enbridge's forecast number of Customers, using the definition of "Customer" from the ABSU CCSA. The fact is, though, that the number of billed customers will be slightly lower, because the term "Customer" includes locked customers (averaging in the range of 20,000 customers) who do not receive monthly bills. Therefore, to calculate a more precise bill impact per customer, one would have to use a forecast number of billed customers for 2012 and a similar forecast for 2013. Given that those forecasts are not part of the evidence in this proceeding, this calculation has not been included. All parties expect, though, that the result would not be materially different from the impacts described in this section of the Settlement Agreement.

All parties also agree that in the event that exogenous factors such as new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period between 2013 and 2018, and those requirements materially change the level of Enbridge's overall costs from those that are set out in the Updated 2013 Template, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the Settlement Agreement will be the same as exists in any Z-factor or similar provision that is included within the ratemaking regime that applies to Enbridge during any particular year between 2013 and 2018. The parties acknowledge that the individual lines in the Updated 2013 Template (other than lines 3 and 10a) are illustrative only, and therefore do not form an appropriate baseline for determination of whether the Z-factor materiality threshold is met. In considering whether a Z-factor materiality threshold is met for customer care costs, it is agreed that two tests must be met. First, the difference between Enbridge's forecast total costs for a year under this Settlement Agreement (calculated by multiplying the agreed cost per Customer for that year in line 17a by the forecast number of Customers for that year) and Enbridge's actual or updated forecast costs for that year for the items set out in the Updated 2013 Template must exceed the threshold. Second, the party claiming Z-factor treatment must establish a specific exogenous event, not taken into account in developing the Template totals, that has caused a net new cost exceeding the threshold. By way of example, if postage rates are increased in a future year, and as a result the postage cost for the year exceeds the amount in the Template by more than the threshold, that will not be sufficient for Z-factor treatment, because it is known that postage rates will change over the 2013 to 2018 term. On the other hand, and by way of further example, if the Company is ordered, by the Board or otherwise, to accept credit card payments for its bills, and the credit card fees imposed on Enbridge exceed the threshold, that could qualify for Z-factor treatment if all other factors are met. (The foregoing examples are intended to assist interpretation of this provision only.) In assessing whether an individual exogenous event caused costs exceeding the threshold, all cost impacts of that event must be included, favourable and unfavourable. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the regulatory rules (including any applicable IRM mechanism) that apply to the Company in any given year.

The parties agree to continue the provision in the 2007 Settlement Agreement dealing with future revenue generating opportunities from the new CIS, as follows:

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including intervenors, may be convened to consider how such opportunities should be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates. Billing services on the Enbridge Gas Distribution bill are covered by a separate process related to open bill access, and are not included in or affected by the provisions set out above.

EVIDENTIARY BASIS FOR THE SETTLEMENT

All parties agree that there is a sufficient evidentiary basis to support the settlement detailed herein. That evidentiary record was built up in a number of ways, including through the prefiled evidence (which includes documentation from the consultative process that led up to the Application) and through a full discovery process, which included written interrogatories, an oral technical conference where representatives of Enbridge and Five Point gave evidence and answered questions, and follow-up questions emanating from the technical conference.

The evidence supporting the settlement is listed in the next sections of this Settlement Agreement, on an issue by issue basis. As can be seen, there are multiple pieces of evidence which are relevant to each of the issues set out in the Board's Issues List.

At a high level, the evidence addresses categories of issues, as follows.

First, Enbridge has provided evidence describing the background to this Application, and the reasons why it is appropriate for the Board to consider an extension of the 2007 Template to address CIS and CC costs for the 2013 to 2018 period. That evidence describes how the Company made decisions to acquire a new CIS and enter into a contract with Accenture for CC services. It also describes the manner in which Enbridge worked with the intervenor steering committee to get agreement upon the process and costs associated with the new CIS and CC contract, and the role played by the intervenor expert (Five Point) in that process. The evidence addresses how the 2007 Template was developed, and then approved and endorsed by the Board. Finally, the evidence sets out how the approach used in the 2007 Template has worked well since that time.

Second, there is a large amount of evidence about the process undertaken by Enbridge to determine how to obtain continued CC services after the current CCSA with Accenture. That evidence describes Enbridge's internal process to identify options for how to proceed, and the decisions taken in that regard. It also describes the participation of the stakeholder steering committee and Five Point in reviewing the Company's actions and making recommendations on how to proceed. The evidence includes explanation of why it was appropriate for the Company to extend and update its CCSA with Accenture, rather than proceeding to an RFP process, along with the endorsement of Five Point to proceeding in that manner. The evidence also includes benchmarking information from EquaTerra and Five Point supporting the reasonableness of the costs set out in the revised and extended Accenture CCSA. Finally, the evidence from both Enbridge and Five Point describes the benefits of the extended and updated CCSA. This topic was the subject of much of the testimony of Five Point and Enbridge at the Technical Conference, and was also the subject of a number of interrogatories and undertakings. All of this evidence serves to support the values set out in line 10a of the 2013 Template.

Third, the evidence sets out the manner in which the new CIS revenue requirement set out in line 3 of the 2013 Template was derived. That evidence describes the provisions of the 2007 Settlement Agreement addressing the anticipated costs of the new CIS and the manner in which those costs would be reflected and potentially adjusted in an opening rate base value at December 31, 2012 (which is the end date of the 2007 Template). The evidence also describes the successful implementation of the new CIS, and the final costs related to that asset. The role of the stakeholder steering committee and Five Point in reviewing and endorsing the implementation of the new CIS and the associated costs is set out in the evidence and in the Technical Conference testimony of Enbridge and Five Point. In that regard, the evidence describes how the updated opening rate base value of $76.9 million for the new CIS was derived and then converted into annual revenue requirement amounts for 2013 to 2018 using the same parameters as employed in the 2007 Template. Finally, the evidence sets out the endorsement of the stakeholder steering committee to the values set out in line 3 of the 2013 Template.

Fourth, the prefiled evidence addresses Enbridge's forecast other CIS and CC costs for 2013 to 2018, as set out in the balance of the 2013 Template. The evidence describes the nature of each of those sets of costs. The evidence also sets out how those forecasts were created, using current costs as a base and then adjusting those costs based upon inflation or contract/third party costs. Many of the interrogatories answered by the Company, as well as the evidence at the Technical Conference and resulting undertakings provide further detail about these costs. As explained herein, the Company's forecast of costs was used as the base from which adjustments were made in order to arrive at a 2013 cost per Customer for other CIS and CC costs.

Fifth, there is discussion in the evidence and in this Settlement Agreement about the financial impact of this settlement on ratepayers. The prefiled evidence explains the customer impact of the proposed 2013 Template, which included an overall revenue requirement amount of $758M. As explained herein, parties have agreed that (based on Enbridge's current Customer forecast), the appropriate revenue requirement to be recovered is $735M. This Settlement Agreement contains details about the total $735M amount of the CC and CIS revenue requirement was derived, and about how that revenue requirement has been smoothed to allow for annual revenue requirements that temper rate volatility. In addition, information is provided about the expected annual rate impact of this Settlement Agreement on a typical Enbridge customer.

DIFFERENCES FROM THE 2007 SETTLEMENT AGREEMENT

The parties have sought to follow the principles established in the 2007 Settlement Agreement and the 2007 Template, including the comprehensiveness of the cost analysis, and the goal of smoothing rate impacts. However, this Agreement and the Updated 2013 Template have certain material differences from the 2007 result, the most important of which are as follows:

- At the time of the 2007 Settlement Agreement, certain of the costs expected to be incurred were not known, including some of the CIS capital costs, and some of the CCSA costs. The 2007 Settlement Agreement contains extensive provisions relating to the true-up of forecast costs to actuals. This Agreement does not contain any true-up provisions, because the costs can be forecast with reasonable accuracy today.

- The 2007 Template resulted in agreement on annual revenue requirement totals, and smoothing on that same basis. This Agreement has added the factor of customer numbers, so that the revenue requirement agreed is per Customer, as is the smoothing method. This makes the smoothing more effective, and reflects the reality that a substantial portion of Enbridge's CC costs vary by number of Customers.

- The 2007 Template had to deal potentially with the costs of transitioning from one service provider to another. In this Agreement, it is known that the incumbent will be retained.

- The 2007 Template was timed to coincide with an Enbridge cost of service application serving as the base year for a multi-year IRM. The timing of this Agreement is driven by the desire of all parties to complete a favourable new CCSA agreement, which must be done prior to the next Enbridge rebasing application.

- The smoothing escalator in the 2007 Template was approximately 1.8% per year. The smoothing escalator in this Agreement is 2.2% per year, based on a cost escalator of 0.6% per year and an adjustment to reduce the 2013 impact on a per Customer basis from a 17.7% increase to 9.1% increase. The net result is a lower level of net cost escalation, coupled with a planned increase in overall service levels.

RESPONSE TO EACH ISSUE

Based upon the Terms of Settlement described above, and based upon the evidence filed in this proceeding, the following represents the response of all parties to each of the issues set out in the Board's Issues List.

1. Are the amounts proposed in the 2013 Template (Line 3) and identified as "New CIS Capital Cost @ Board Approved 36% Equity" appropriate for recovery?

As discussed above in the "Terms of Settlement" section (see pages 12 to 14), for the purposes of determining an annual cost per Customer for CIS and CC services set out in the Updated 2013 Template, all parties agree that the amounts proposed in Line 3 of the Updated 2013 Template for the revenue requirement for the new CIS Asset from 2013 to 2018 are appropriate. Those revenue requirement amounts are based upon an opening rate base value of $76.9M for the new CIS asset as of January 1, 2013.

The amounts in line 3 are calculated by using all of the same parameters (including cost of capital) for the calculation of resulting revenue requirement of the new CIS as were used in the calculation of the values in line 3 of the 2007 Template. All parties agree that the use of these parameters for the calculation of the line 3 revenue requirement in the Updated 2013 Template (including, for example, the 8.39% ROE value that is being used) is not intended as a precedent for any future proceedings and is without prejudice to the right of any party to assert that a different approach should be used for the calculation of revenue requirement for capital assets in any future proceedings.

As part of the agreement in respect of the recovery of costs associated with its new CIS, the parties agree that it is assumed that Enbridge will not replace or undertake major revisions to the new CIS prior to 2019. Enbridge agrees that if it seeks to close to rate base any CIS capital costs relating to this new CIS or a replacement CIS exceeding on a cumulative basis $50 million between January 1, 2013 and December 31, 2018, then Enbridge will make specific application for Board approval for such action. All parties are free to take whatever positions they consider appropriate on that application. Any such request by Enbridge shall, however, start from the assumption that the appropriate rate consequences (including depreciation, return, taxes, etc.)

are those that most closely track the rate consequences that would occur if the new capital assets were purchased, developed or built, and closed to rate base, in 2019.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-10	Rationale for the CIS cost recovery over two six-year spans
I-1-33	Copy of 2007 Settlement Agreement
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.2	Five Point slide deck re. CIS implementation project costs
JTC1.3	Annual cost per customer for CIS services up to 2018

2. Are the amounts proposed in the 2013 Template (Line 4) and identified as "New CIS Hosting and Support" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 81-83, 101-105 and 124-125
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)
JTC1.8	Breakout of costs in row 4 of the 2013 Template for 2010 to 2012

3. Are the amounts proposed in the 2013 Template (Line 5) and identified as "CIS Backoffice (EGD Staffing)" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 128-129
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

4. Are the amounts proposed in the 2013 Template (Line 6) and identified as "SAP Licence Fees" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-2	Explanation of CIS costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
JTC1.3	Annual cost per customer for CIS services up to 2018
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

5. Are the amounts proposed in the 2013 Template (Line 10) and identified as "New Service Provider Contract Cost" appropriate for recovery?

All parties agree that the costs on this line (except those that relate to line 10a) should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals. All parties agree that the costs on line 10a are a reasonable forecast, measured on a per Customer basis, of the costs payable for regulated activities under the CCSA.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-9	Explanation of how new ABSU CCSA costs are addressed during term of 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-12	Copy of ABSU CCSA
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-15	Discussion of cost drivers in the ABSU CCSA and about how contract revenue is derived
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
I-1-19	Explanation of how Enbridge addressed the areas identified as "challenges" in the "Customer Care Service Delivery Strategy" document
I-1-20	Explanation of how ratepayers and others are getting / will get good value from the ABSU CCSA
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 62-64 and 98
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

6. Are the amounts proposed in the 2013 Template (Line 10a) and identified as "ACN, MTP & Collection Agency costs" appropriate for recovery?

As discussed above in the "Terms of Settlement" section (see pages 14 to 18), and subject to all the other provisions of this Agreement, for the purposes of determining an annual cost per Customer for CIS and CC services set out in the Updated 2013 Template, all parties agree to the amounts proposed in Line 10a of the Updated 2013 Template for Accenture, MTP and Collection

Agency Costs from 2013 to 2018. Unlike the approach used in the 2007 Template, the costs set out in line 10a of the Updated 2013 Template do not include the LVB costs, which have been moved to line 12.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-9	Explanation of how new ABSU CCSA costs are addressed during term of 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-1-12	Copy of ABSU CCSA
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-15	Discussion of cost drivers in the ABSU CCSA and about how contract revenue is derived
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
I-1-19	Explanation of how Enbridge addressed the areas identified as "challenges" in the "Customer Care Service Delivery Strategy" document
I-1-20	Explanation of how ratepayers and others are getting / will get good value from the ABSU CCSA
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 62-64, 70-72, 98, 108-110, 129-130
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

7. Are the amounts proposed in the 2013 Template (Line 10b) and identified as "MET" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document

B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, p. 110
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

8. Are the amounts proposed in the 2013 Template (Line 10c) and identified as "Postage" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-11	Explanation of how contract costs other than the new ABSU CCSA costs are determined during term of 2013 Template (given that some do not have 6 year terms)
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Five Point at TC, p. 111
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

9. Are the amounts proposed in the 2013 Template (Line 11) and identified as "Customer Care Licences" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

10. Are the amounts proposed in the 2013 Template (Line 12) and identified as "Customer Care Backoffice (EGD Staffing)" appropriate for recovery?

All parties agree that the costs on this line should be aggregated with all other lines (excluding lines 3 and 10a), and forecast on the basis of the per Customer amount and formula described on pages 20 to 22 above. The costs for this line as set in the 2013 Template are for illustrative purposes only, and are not separately validated in isolation from the totals.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-4	Stakeholder Steering Committee Statement of Principles
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-3	Explanation of Customer Care costs in 2013 Template
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 70-72, 108-110 and 129-130
JTC1.5	Updated 2013 Template that moves Large Volume Billing costs from line 10a to line 12
JTC 1.6	Updated annual costs for column E (2011 costs) of the 2013 Template (B-5-2)

11. Are the amounts proposed in the 2013 Template (Line 23) and identified as "Total Customer Care Revenue by Year (including repayment of 2007 variance)" appropriate for recovery?

As described above in the "Terms of Settlement" section (see pages 10 to 24), all parties agree that the amounts identified in line 24 as the "smoothed" cost per Customer for each year from 2013 to 2018 are appropriate for recovery. On the assumption that the actual annual numbers of

Customers are the same as those set out in line 17, all parties agree that the amounts set out in line 23 of the Updated 2013 Template for total annual revenue requirement (which total $735M) are appropriate for recovery in the appropriate years. In this regard, it is noted that the actual annual revenue requirement to be recovered each year will vary from line 23, because it will be calculated each year by multiplying the annual "smoothed" cost per Customer in line 24 by Enbridge's updated forecast number of Customers for that year. All parties agree that this adjustment from the $735 million as a result of changes in the number of Customers is appropriate.

In conjunction with this "smoothing" approach, parties agree to the establishment and operation of a rate smoothing deferral account for each year from 2013 to 2018, as described above in the "Terms of Settlement" section.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-1-6	Inflation factor approved in each year of the IRM Plan
I-1-7	Inflation factors proposed for CIS and CC costs
I-1-8	Explanation of the smoothing mechanisms built into the 2013 Template
I-1-23	Explanation of which items in the 2013 Template contain Enbridge's in-house costs
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 64-69, 72-80, 86-92, 115-118, 131-132 and 137-144
JTC1.4	Calculation of annual cost per customer for CIS and CC services up to 2018
JTC1.7	Forecast of GDP IPI FDD factor for 2012 to 2018
JTC 1.9	Update of inflation factors proposed for CIS and CC costs
JTC1.10	Explanation of difference between 2012 and 2013 smoothed revenue requirement in 2013 Template
JTC 1.11	Recalculation of smoothed annual revenue requirement in 2013 Template from 2012 to 2018, to reflect equal annual increases
JTC 1.13	Revised version of 2013 Template that removes one-time costs associated with acquiring new CIS and initial CCSA with ABSU

12. Is the proposed opening 2013 Rate Base amount of $76.9 million for the CIS asset appropriate?

As described above in the "Terms of Settlement" section (see pages 12 to 14), all parties agree to the proposed opening 2013 Rate Base amount of $76.9 million for the new CIS asset. See also the response to Issue #1.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-1	Plain language description of each line item in the 2013 Template
I-1-2	Variance analysis for each line item in the 2013 Template
I-1-3	Variance analysis between forecast and actual values in 2007 Template
I-1-4	Variance analysis for 2013 new CIS opening rate base value

I-1-10	Rationale for the CIS cost recovery over two six-year spans
I-1-33	Copy of 2007 Settlement Agreement
I-2-2	Explanation of CIS costs in 2013 Template
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.2	Five Point slide deck re. CIS implementation project costs
JTC1.3	Annual cost per customer for CIS services up to 2018

13. Is the annual adjustment factor (or inflation factor) of 1.77580% built into the 2013 Template appropriate?

As described above in the “Terms of Settlement” section (see pages 10 to 24), the Updated 2013 Template is different from the 2013 Template filed with this Application. The Updated 2013 Template uses different inflation factors for Enbridge’s cost per Customer (derived as a function of the underlying costs) and for the smoothed cost per Customer amount to be recovered each year in revenue requirement. All parties agree that the inflators used for the purpose of creating costs per Customer for 2014 to 2018 (which apply an annual increase of 0.6%), and for creating the smoothed annual cost per Customer to be recovered each year in revenue requirement (which apply an annual increase of 2.2%, but use a lower 2013 base cost per Customer amount) are compromise numbers that create reasonable and appropriate results in this case, but also agree that these inflators will not be relied upon as a precedent or indicator of an appropriate inflator of costs, revenue requirement or rates in any other Enbridge proceeding.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Costs
I-2-5	Explanation of how costs in 2013 Template were inflated
Tech Conf	Evidence of Enbridge at TC, pp. 74-78, 86-88 and 131-132
JTC1.7	Forecast of GDP IPI FDD factor for 2012 to 2018
JTC 1.9	Update of inflation factors proposed for CIS and CC costs

14. Is it appropriate for the cost recovery to span two 6-year fiscal periods (2007- 2012 and 2013-2018 as shown on the 2013 Template) when the economic life of the CIS asset is ten years?

All parties agree that the recovery of revenue requirement for the new CIS asset over a 10 year term from 2009 to 2018 is appropriate. That is consistent with the fact that the new CIS asset is assumed to have a 10 year economic life, with an assumed in-service date of January 1, 2009.

All parties agree that it is appropriate that the additional cost allowances included in the January 1, 2013 $76.9M opening rate base amount for the new CIS asset should continue into 2019 in recognition of the actual CIS in-service date of September 1, 2009. The result, as set out at Ex. B-3-4, is that Enbridge will collect approximately $760,000 in revenue requirement for the new CIS asset in 2019.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-4	Revenue Requirement Impact of New CIS Opening Rate Base Value
B-5-1	Explanatory Notes re. 2013 Template
I-1-10	Rationale for the CIS cost recovery over two six-year spans

15. Are the efficiency and performance measures that are built into the Accenture contract adequate and appropriate?

As described above in the "Terms of Settlement" section (see pages 14 to 18), all parties agree that, with respect to customer care associated with regulated Customers, and excluding those aspects that relate to unregulated and non-utility activities, such as open bill access and ABC, the extended and updated Accenture CCSA, and the associated cost per Customer, is prudent and appropriate. The service levels and performance measures in the revised and extended CCSA are superior to those which are included in the current CCSA. Under the revised and extended CCSA, Accenture has agreed to provide its services at a predetermined cost for an extended period of time on a per-Customer basis. Accenture therefore takes the risk of achieving or not achieving productivity benefits. Enbridge and its ratepayers get the benefit of predetermined customer care costs which are comparable to current costs through to the end of 2018. On this basis, no party asserts that with respect to regulated activities the Accenture contract lacks adequate or appropriate efficiency and performance measures.

Evidence: The evidence in relation to this issue includes the following:

B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-20	Explanation of how ratepayers and others are getting and will get good value from the ABSU CCSA
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.1	Five Point explanation of recommendations made to Enbridge and Enbridge's responses

16. Are the efficiency and performance measures that are built into all the subject outsourced contracts, other than the Accenture contract, adequate and appropriate?

As described in the "Terms of Settlement" section (see pages 18 to 22), all parties agree that the costs included on a cost per Customer basis as the "other CIS and CC costs" (from lines 4, 5, 6, 10b, 10c, 11 and 12 of the Updated 2013 Template) are in the aggregate prudent and appropriate. Those lines include costs associated with outsourced contracts, such as the MET (meter reading) contract. Given the negotiated reduction in costs from the level forecast by Enbridge for 2013, and given the certainty that will result from annual increases in cost per Customer that are set at less than 1% (on a non-smoothed basis), all parties agree that in aggregate the cost consequences of those contracts are reasonable.

Evidence: The evidence in relation to this issue includes the following:

B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
I-1-14	Description of cost efficiency and incentive measures built into the new ABSU CCSA
I-1-16	Discussion of self-service features of ABSU CCSA
I-1-20	Explanation of how ratepayers and others are getting and will get good value from the ABSU CCSA
Tech Conf	Evidence of Five Point at TC, pp. 12-33, 30, 40-41 and 57-58
Tech Conf	Evidence of Enbridge at TC, pp. 60-62, 84-86, 92-98, 99-101 and 122-123
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations
I-1-21	Details of each of the outsourced contracts, other than the ABSU CCSA

17. Is Y-Factor treatment of all of the subject costs appropriate in the next generation of the Board's Incentive Ratemaking?

All parties agree that Y-factor treatment of all the subject costs is appropriate in any next generation of IRM ratemaking that applies to Enbridge. While all parties recognize that the nature of a large number of the costs in the Updated 2013 Template are such that they would not normally be considered Y-factors, the fact that the annual levels of these costs have been predetermined by settlement over a number of years means that they should be included in any IRM-based rates for Enbridge in the same manner as traditional Y-Factors. This position is supported by the fact that the cost per Customer set out in the Updated 2013 Template was established using an IRM-type approach, where a base level for all costs was established, and then an annual inflation factor was applied to those base costs to establish costs per Customer for successive years. Given that the annual revenue requirements that will be determined each year are a function of the costs per Customer that were established using an IRM-type approach, it is appropriate that the annual revenue requirement amounts be passed through as a Y-Factor each year of any future IRM term, or as a pass-through amount in any cost of service ratemaking year between 2013 and 2018.

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-31	Board Staff Interrogatory #31

18. Is the nature of the tendering process carried out adequate and appropriate in the circumstances?

As described above in the "Terms of Settlement" section (see pages 14 to 18), all parties agree that the process followed by Enbridge in considering options for customer care services after the expiry of the current Accenture CCSA (as of April 1, 2012), and then negotiating an revised and extended CCSA with Accenture was appropriate and provided proper ratepayer protection in developing the pricing and terms of the CCSA for the term covered by the Updated 2013 Template. All parties agree that the procurement approach used was unique to the particular circumstances, and its applicability, if at all, as a precedent for future procurements by Enbridge or any other utility is dependent on the particular circumstances in that future procurement.

Evidence: The evidence in relation to this issue includes the following:

B-2-2	Overview of Relief Sought
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document
B-4-4	Stakeholder Steering Committee Statement of Principles
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-18	Explanation of how Enbridge addressed recommendations from Five Point
JTC1.1	Five Point explanation of recommendations made to Enbridge during ABSU negotiations, and Enbridge's responses to those recommendations

19. Should any of the proposed costs be classified as Non-Utility costs?

As described above in the "Terms of Settlement" section (see page 25), all parties agree that any issue over whether any of the costs set out in the Updated 2013 Template (and the associated annual cost per Customer) should be classified as "Non-Utility Costs" with the consequential possibility that some of the costs may be allocated to third parties is more appropriately raised as part of Enbridge's ratesetting proceedings for 2013 and beyond, to be considered in light of the Company's activities at that time.

Evidence: The evidence in relation to this issue includes the following:

A-2-2	2013 Template
B-5-1	Explanatory Notes re. 2013 Template
B-5-2	Version of 2013 Template Containing Actual/Forecast 2007 to 2012 Cost
I-1-1	Plain language description of each line item in the 2013 Template
I-1-24	Explanation of non-utility services provided related to costs set out in this Application
I-1-25	Explanation of operations of CIS and CC systems in serving non-utility stakeholders
I-1-26	Explanation of whether non-utility services are supported by the CIS and CC systems
I-1-27	Explanation of open bill features associated with this Application and how open bill revenue is shared
I-1-28	Explanation of how bad debt, open bill access and agent billing and collection costs are treated in the context of this Application
I-2-6	Explanation of current and future open bill access costs and revenues
Tech Conf	Evidence of Enbridge at TC, pp. 105-107, 112-114 and 118-122
JTC1.12	Breakdown of information provided in I-2-6
JTC1.14	Explanation of costs removed from ABSU CCSA and moved to open bill and agent billing and collection

20. Is the benchmarking of costs appropriate for use in the Board's assessment of the reasonableness of the costs?

All parties agree that the benchmarking information provided in this application from EquaTerra and Five Point is appropriate for use in the Board's assessment of the reasonableness of the costs in lines 3 and 10a of the Updated 2013 Template. All parties further agree that the benchmarking information from EquaTerra and Five Point support a finding that the costs set out for the new CIS asset (line 3) and the revised and extended CCSA (line 10a) are reasonable.

Evidence: The evidence in relation to this issue includes the following:

B-2-2	Overview of Relief Sought
B-3-1	CIS Costs
B-3-2	Five Point's CIS Project Close-Out Report
B-4-1	Customer Care Costs
B-4-2	Five Point's Customer Care Consultative Report
B-4-3	Enbridge's Customer Care Strategy Document (including EquaTerra benchmarking evidence)
B-4-4	Stakeholder Steering Committee Statement of Principles
I-1-13	Explanation of why no tendering process was undertaken to renew ABSU CCSA
I-1-17	Statement of Work for Five Point consulting services
I-1-29	EquaTerra benchmarking reports
Tech Conf	Evidence of Five Point at TC, pp. 10-12, 30, 34-40 and 42-47
JTC1.2	Five Point slide deck re. CIS implementation project costs

21. Is the Application consistent with the 2007 Settlement Agreement in all material respects?

As described above in the "Terms of Settlement" section (see pages 12 to 14), the one change to the details of the 2007 Settlement Agreement, which change was contemplated by the terms of that Settlement Agreement, is that all parties agree that the proper opening rate base value for the new CIS as of January 1, 2013 is $76.9 million.

Beyond that, all parties agree that this Settlement Agreement is consistent with the 2007 Settlement Agreement in all material respects. The terms of this Settlement Agreement do not change any items in the 2007 Template that was attached to the 2007 Settlement Agreement, and in particular the terms of this Settlement Agreement do not in any way impact upon the revenue requirement being recovered for CIS and CC services in 2011 and 2012, as set out in the 2007 Settlement Agreement. In addition, to large extent the approach taken in the current Settlement Agreement, and the Updated 2013 Template, replicates the approach taken in the 2007 Settlement Agreement. On page 28 above the parties have set out the material differences in approach used in this Agreement vs. the 2007 Settlement Agreement. All of those differences in approach are either the result of changed circumstances (such as no continuing need for true-up provisions) or updates to the concepts in the 2007 Settlement Agreement (such as the change of smoothing to a per Customer basis).

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-30	Explanation of how the Application is consistent with the 2007 Settlement Agreement
I-1-33	Copy of 2007 Settlement Agreement
I-1-34	Copy of EB-2006-0034 transcript where OEB approved 2007 Settlement Agreement

22. Is the Application consistent with the existing IRM mechanism and will it be applicable to the future IRM mechanism?

All parties agree that this Settlement Agreement will have no impact upon the current IRM mechanism, as it does not contemplate any revenue requirement impacts during the term of the current IRM term (up to December 31, 2012).

All parties further agree that this Settlement Agreement will be applicable to any future IRM mechanism that applies to Enbridge during the term of the Updated 2013 Template. As explained above in the "Terms of Settlement" section, in a future IRM mechanism, the annual CIS and CC revenue requirement (calculated by multiplying the applicable cost per Customer by the applicable number of Customers) would be passed through into overall revenue requirement as a Y-factor, which is a continuation of the current practice.

Evidence: The evidence in relation to this issue includes the following:

I-1-22	Explanation of how there is no variance account / true-up for differences between amounts in 2007 and 2013 Template and actual costs
I-1-31	Explanation of how the Application is consistent with the existing IRM mechanism and how it will be applicable to the future IRM mechanism

23. Is the rate class cost allocation methodology appropriate?

As described above in the "Terms of Settlement" section (see page 24), all parties agree that it is not necessary to address any issues in this proceeding about the allocation of the costs set out in the Updated 2013 Template to rate classes. All parties agree that any issues about how the costs set out in the Updated 2013 Template are allocated to rate classes may be raised as part of Enbridge's ratesetting proceedings for 2013 and beyond.

Evidence: The evidence in relation to this issue includes the following:

I-1-32	Explanation of rate class allocation and bill impact of the cost consequences of the 2013 Template
I-2-7	Explanation of cost allocations and bill impact associated with the 2013 Template

24. Are the customer bill impacts appropriate?

As described above in the "Terms of Settlement" section (see pages 24 to 25), all parties agree that the customer bill impacts of this Settlement Agreement are appropriate.

Evidence: The evidence in relation to this issue includes the following:

I-1-32	Explanation of rate class allocation and bill impact of the cost consequences of the 2013 Template
I-2-7	Explanation of cost allocations and bill impact associated with the 2013 Template

"Updated 2013 Template"

#	Category of Cost	A 2007A	B 2008A	C 2009A	D 2010A	E 2011	F 2012	G 2007-2012 Total	H 2013	I 2014	J 2015	K 2016	L 2017	M 2018	N 2013-2018 Total
	CIS Related Categories														
1	*Old CIS Licence Fee*														
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000	$0	$0	$0	$0	$0	$0	$0
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*														
3	*New CIS Capital Cost @ Board Approved **36%** Equity*	$0	$0	$950,000	($5,260,000)	$25,890,000	$24,910,000	$46,490,000	$25,420,000	$24,380,000	$23,320,000	$22,320,000	$21,310,000	$20,260,000	$137,010,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000	$7,107,911	$7,355,128	$7,628,087	$7,934,598	$8,237,974	$8,350,643	$46,614,341
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254	$2,611,281	$2,711,307	$2,822,435	$2,946,817	$3,070,921	$3,124,554	$17,287,314
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500	$2,097,486	$2,188,393	$2,289,104	$2,401,538	$2,514,778	$2,571,070	$14,062,369
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$15,200,000**	**$10,830,000**	**$14,313,500**	**$8,727,000**	**$38,938,800**	**$38,022,454**	**$126,031,754**	**$37,236,678**	**$36,634,828**	**$36,059,626**	**$35,602,954**	**$35,133,673**	**$34,306,266**	**$214,974,024**
	Customer Care Related Categories														
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000	$0	$0	$0	$0	$0	$0	$0
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sept. 30, 2008*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	$47,803,098	$66,069,140	$67,251,948	$68,885,212	$ 70,731,432	$ 72,542,088	$393,282,918	$69,831,641	$73,010,836	$76,245,351	$79,424,943	$82,682,196	$86,349,139	$467,544,106
10a	*ACN, MTP & Collection Agency costs*	-	-	-	-	-	-	-	46,022,920	47,751,346	49,354,748	50,736,108	52,168,283	54,755,784	300,789,189
10b	*MET*	-	-	-	-	-	-	-	$9,583,608	$9,957,362	$10,465,311	$11,034,609	$11,610,927	$11,904,271	$64,556,086
10c	*Postage*	-	-	-	-	-	-	-	$14,225,114	$15,302,128	$16,425,293	$17,654,226	$18,902,986	$19,689,083	$102,198,830
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000	$1,289,750	$1,345,649	$1,407,576	$1,476,712	$1,546,344	$1,580,958	$8,646,987
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071	$6,484,645	$6,792,953	$7,129,522	$7,506,674	$7,876,385	$8,044,707	$43,834,885
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000	$0	$0	$0	$0	$0	$0	$0
14	*Transition Costs - Consultants and ISP*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	*Transition Costs - EGD Staffing*														
	Subtotal Customer Care Only	**69,203,098**	**71,642,140**	**72,920,738**	**74,652,666**	**76,600,509**	**78,515,838**	**443,534,989**	**77,606,036**	**81,149,437**	**84,782,449**	**88,408,328**	**92,104,924**	**95,974,803**	**520,025,978**
16	**Total CIS & Customer Care**	$84,403,098	$82,472,140	$87,234,238	$83,379,666	$115,539,309	$116,538,292	$569,566,743	$114,842,714	$117,784,265	$120,842,075	$124,011,282	$127,238,597	$130,281,069	$735,000,002
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613	2,059,959	2,100,317	2,142,191	2,185,464	2,229,173	2,269,074	12,986,178
17a	**Total cost/customer**	$46.09	$43.91	$45.30	$42.25	$57.15	$56.31		$55.75	$56.08	$56.41	$56.74	$57.08	$57.42	
22	***The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.***	**$90,799,999**	**$92,412,426**	**$94,053,486**	**$95,723,687**	**$97,423,549**	**$99,153,596**	$569,566,743							
23	*Total Customer Care Revenue By Year (Including repayment of 2007 variance)*	$ 90,800,000	$ 92,412,426	$ 94,053,486	$ 95,723,687	$ 97,423,549	$ 99,153,596	$569,566,743	110,207,807	114,837,889	119,703,021	124,806,484	130,101,959	135,342,842	735,000,002
24	*Normalized Customer Care Revenue Requirement Per Customer without Bad Debt*	$ 49.58	$ 49.21	$ 48.84	$ 48.50	$ 48.19	$ 47.91		$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65	

"Updated CIS / CC Template for 2014 - 2018"

#	Category of Cost	A 2007A	B 2008A	C 2009A	D 2010A	E 2011	F 2012	G 2007-2012	H 2013	I 2014	J 2015	K 2016	L 2017	M 2018	N 2013-2018
	CIS Related Categories							*Total*							*Total*
1	*Old CIS Licence Fee*														
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000	$0	$0	$0	$0	$0	$0	$0
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*														
3	*New CIS Capital Cost @ Board Approved **36%** Equity*	$0	$0	$950,000	($5,260,000)	$25,890,000	$24,910,000	$46,490,000	$25,420,000	$24,380,000	$23,320,000	$22,320,000	$21,310,000	$20,260,000	$137,010,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000	$7,107,911	$7,355,128	$7,628,087	$7,934,598	$8,237,974	$8,350,643	$46,614,341
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254	$2,611,281	$2,711,307	$2,822,435	$2,946,817	$3,070,921	$3,124,554	$17,287,314
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500	$2,097,486	$2,188,393	$2,289,104	$2,401,538	$2,514,778	$2,571,070	$14,062,369
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$15,200,000**	**$10,830,000**	**$14,313,500**	**$8,727,000**	**$38,938,800**	**$38,022,454**	**$126,031,754**	**$37,236,678**	**$36,634,828**	**$36,059,626**	**$35,602,954**	**$35,133,673**	**$34,306,266**	**$214,974,024**
	Customer Care Related Categories														
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000	$0	$0	$0	$0	$0	$0	$0
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sept. 30, 2008*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	$47,803,098	$66,069,140	$67,251,948	$68,885,212	$ 70,731,432	$ 72,542,088	$393,282,918	$69,831,641	$73,010,836	$76,245,351	$79,424,943	$82,682,196	$86,349,139	$467,544,106
10a	*ACN, MTP & Collection Agency costs*	-	-	-	-	-	-	-	46,022,920	47,751,346	49,354,748	50,736,108	52,168,283	54,755,784	300,789,189
10b	*MET*	-	-	-	-	-	-	-	$9,583,608	$9,957,362	$10,465,311	$11,034,609	$11,610,927	$11,904,271	$64,556,086
10c	*Postage*	-	-	-	-	-	-	-	$14,225,114	$15,302,128	$16,425,293	$17,654,226	$18,902,986	$19,689,083	$102,198,830
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000	$1,289,750	$1,345,649	$1,407,576	$1,476,712	$1,546,344	$1,580,958	$8,646,987
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071	$6,484,645	$6,792,953	$7,129,522	$7,506,674	$7,876,385	$8,044,707	$43,834,885
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000	$0	$0	$0	$0	$0	$0	$0
14	*Transition Costs - Consultants and ISP*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	*Transition Costs - EGD Staffing*														
	Subtotal Customer Care Only	**69,203,098**	**71,642,140**	**72,920,738**	**74,652,666**	**76,600,509**	**78,515,838**	**443,534,989**	**77,606,036**	**81,149,437**	**84,782,449**	**88,408,328**	**92,104,924**	**95,974,803**	**520,025,978**
16	**Total CIS & Customer Care**	$84,403,098	$82,472,140	$87,234,238	$83,379,666	$115,539,309	$116,538,292	$569,566,743	$114,842,714	$117,784,265	$120,842,075	$124,011,282	$127,238,597	$130,281,069	$735,000,002
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613	2,059,959	2,100,317	2,142,191	2,185,464	2,229,173	2,269,074	12,986,178
17a	**Total cost/customer**	$46.09	$43.91	$45.30	$42.25	$57.15	$56.31		$55.75	$56.08	$56.41	$56.74	$57.08	$57.42	
22	***The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.***	**$90,799,999**	**$92,412,426**	**$94,053,486**	**$95,723,687**	**$97,423,549**	**$99,153,596**	$569,566,743							
23	*Total Customer Care Revenue By Year (Including repayment of 2007 variance)*	$ 90,800,000	$ 92,412,426	$ 94,053,486	$ 95,723,687	$ 97,423,549	$ 99,153,596	$569,566,743	110,207,807	114,837,889	119,703,021	124,806,484	130,101,959	135,342,842	735,000,002
24	*Normalized Customer Care Revenue Requirement Per Customer without Bad Debt*	$ 49.58	$ 49.21	$ 48.84	$ 48.50	$ 48.19	$ 47.91		$ 53.50	$ 54.68	$ 55.88	$ 57.11	$ 58.36	$ 59.65	
25	**Updated Line 17 Number of customer forecasts for 2014 - 2016**								**2,059,959**	**2,086,534**	**2,124,101**	**2,163,168**	**2,202,848**	**2,242,859**	
26	**Updated Line 16 Total CIS & Customer Care costs**								**$ 114,842,714**	**$ 117,011,324**	**$ 119,821,609**	**$ 122,746,125**	**$ 125,735,997**	**$ 128,775,910**	
27	**Updated Line 23 Total Customer Care Revenue by year**								**$ 110,207,807**	**$ 114,084,283**	**$ 118,692,174**	**$ 123,533,214**	**$ 128,565,544**	**$ 133,779,203**	

Witnesses: K. Culbert
S. McGill

O&M BUDGET – FINANCE

Mandate and Responsibilities

1. The mandate of the Finance Department is to provide the Company's customers with sharper insights and trusted advice through partnerships to enable greater effectiveness in execution of Company strategies. The Finance Department is responsible for accounting, financial and management reporting, budgeting, long range planning, performance management, taxation, capital and portfolio management, investment review, economic and market analysis, strategic planning, business analytics and audit services, and internal controls.

Services and Activities

2. The Finance department has changed since the 2013 Test Year filing EB-2011-0354. At that time Finance consisted of the Controllers Group, the Business Performance Group and Internal Audit. In January 2013, there was a reorganization, whereby the majority of Finance functions and personnel were moved to and consolidated within the Finance Department.

3. The Finance Department is now composed of five functional areas, which are the Controllers Group, Internal Audit, Incentive Regulation Financial Planning, Strategy, Planning & Analytics and Financial Business Performance.

Controllers Group

4. The Controllers Group is responsible for overall financial, management and capital accounting and reporting compliance activities, and is composed of the Tax Services, Assistant Controllers and Capital & Gas Accounting teams.

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

5. The Tax services group is responsible for overall income and commodity tax compliance, preparation of income and commodity tax returns and filings as well as the identification of tax saving opportunities. The Assistant Controllers group is responsible for all internal monthly financial reporting, quarterly and annual external financial reporting, working capital management which includes cash management, accounts payable processing, accounting research and cost allocation. The Capital & Gas Accounting group oversees the accounting and reporting on Property, Plant and Equipment and Intangible Assets as well as the reporting and analysis on Gas distribution margin and other gas related accounting processes.

Internal Audit

6. Internal Audit activities include providing the business with objective, expert advice in the areas of assurance and governance. The Internal Audit group focuses on critical risks and issues facing the business and addressing them through the execution of the audit plan. They are also responsible for overseeing the Company's internal reporting over financial reporting initiatives and also provide assistance to the Company's external auditors in the execution of quarterly reviews and the annual audit, which helps to manage audit fees.

Incentive Regulation Financial Planning

7. Incentive Regulation Financial Planning activities primarily consist of leading the coordination between Finance and other departments in the development of the Company's Incentive Regulation plan.

Strategy, Planning and Analytics Group

8. The Strategy, Planning and Analytics group is responsible for Capital & Portfolio Management, Investment Review, Economic & Market Analysis, Business Productivity Analytics & Reporting and Customer Analytics. Capital and Portfolio

Management is responsible for the overall capital management process, which includes governance activities, development and enforcement of policies and procedures, portfolio optimization, development and maintenance of capital tracking processes and systems, and tracking of benefits realization. The Investment Review group assess the feasibility of investment options, business strategies, infrastructure expansion and new products. The group also works with the business in managing new initiatives at various stages, including identification, due-diligence, assessment, budgeting and post implementation audit to ensure the Company's financial performance targets are met.

9. The Economic and Market Analysis group supports the regulatory process for the Company through fiscal year forecasts of degree days, average use, Unbilled & Unaccounted for Gas ("UUF"), Return on Equity ("ROE") regional economic indicators, and customer additions. The group also supports the Long Range Plan and corporate budget process through long term forecasts for average uses, unlocks, volumes, customer additions, economic indicators, late payment penalties, and ROE. The group maintains forecasts and comparisons of natural gas' price advantage relative to electricity, oil, and propane for different customer classes; pricing is updated every QRAM and forms an integral part of the external communications carried out quarterly. The group also supports the Controller's month-end processes through degree day tracking, unbilled forecasts, and other validation protocols.

10. The Business Productivity Analytics and Reporting team works with business stakeholders to identify and report productivity opportunities, and provide business analytics to support business operations. The Customer Analytics Group is responsible for managing customer growth portfolio and policies and ensures that

the Company's financial performance targets are met. They develop customer additions forecast (LRP and Budget), and monitor and report upon the performance during the year. The group is also responsible for working with the Business Development group. Finally, the group also provides regulatory evidence to support the Company's Economic Feasibility Procedure and Policy, customer growth forecast and Natural Gas Vehicle program during rate case filings.

<u>Financial Business Performance Group</u>

11. The Financial Business Performance Group is composed of the Operational Finance Team, the Performance and Risk Management Team and the Forecast, Budget and Planning Team.

12. The Operational Finance Group is composed of a team of Finance Business Partners and supporting analysts who provide support to the Department Management groups with respect to all financial matters and strategic direction to achieve the Company's overall goals and objectives. This group performs financial analysis, scorecard reporting, and monthly reporting for all departments within the company. They also provide monthly Department Capital and O&M Forecasts, FTE and Headcount reporting, assist in compiling Long Range Plans and Annual Budgets and liaise with the appropriate departments ensuring mission critical IT system interface support.

13. The Performance and Risk Management group are responsible for the creation and maintenance of a robust business performance management system and supporting processes, including leading the development of the annual corporate scorecard that is aligned with Company strategy, challenging key performance indicators, targets, and outcomes and validating performance results. On the Risk Management side, this group is responsible for the development and

implementation of an integrated risk management framework to support continuous updating and monitoring of risks facing the Company. This includes maintaining and monitoring of the Company's risk register which supports the corporate risk assessment process and development of the audit plan. The group also reviews and validates current risk mitigation controls and programs for their effectiveness. The group is also responsible for researching and assessing best practices in the areas of performance and risk management and its applicability to the Company.

14. The Forecast, Budget and Planning Team is responsible for the Annual Budget. This includes developing the annual volume and customer budget, consolidating the O&M and capital budgets. The group is responsible for coordinating and updating the monthly forecast, performing actual to budget variance analysis and providing the results to management for decision support. The Group also supports the development of the Long range plan and financial modeling and analytics used to support rate case applications.

2013 to 2016 O&M Budget for Finance

15. A summary of the 2013, 2014, 2015 and 2016 O&M budget by major expense type for Finance is presented in Table 1.

Finance Department
O&M by Expense Type - 2013 to 2016
Table 1

Line No.	O&M Costs ($000's)	2013 Budget	2014 Budget	2015 Budget	2016 Budget
1	Salaries and Wages	11,775	11,431	11,269	11,592
2	Capitalization	(1,499)	(1,562)	(1,607)	(1,653)
3	Net Salaries & Wages	10,276	9,870	9,662	9,940
4	Travel and Entertainment	601	559	525	488
5	Outside Services	879	464	441	444
6	Other	240	235	239	243
7	Audit Fees	1,594	1,616	1,643	1,671
8	Sub-total	13,589	12,745	12,510	12,786
9	Internal Recoveries	(2,136)	(1,027)	(531)	(537)
10	Total Finance	11,453	11,717	11,979	12,249
11	FTE	133	130	125	125

16. The budget for the Finance Department is $11.7, $12.0 and $12.3 million respectively for the years 2014, 2015 and 2016 as presented in Table 1 above. The 2014 overall budget is an increase of 1.7% over 2013, while the 2015 budget is an increase of 2.6% over 2014 and the 2016 budget is a 2.5% increase over 2015.

17. Gross Salaries and wages account for nearly 95% of the Finance total O&M budget for each year. Given its labour-intensive nature, it is critical for Finance to retain well-trained, knowledgeable, and competitively compensated professionals to effectively execute the Finance Department's function and mission. Salaries and wages are lower in 2014 vs. 2013 as a result of FTE reductions, which is partially offset by a modest salary increase.

18. Capitalized salaries and wages represent the portion of Finance staff salaries and wages that are capitalized as the nature of the work directly supports capital projects and initiatives. The increase from 2013 is due to a slight increase in the

amount of capital related work being performed by the group coupled with a modest budgeted increase in union wages, as per the collective bargaining agreement.

19. Travel and entertainment costs reflect the cost of Finance staff attending conferences, training, and audit work. These costs are budgeted at 7% lower in 2014 vs. 2013.

20. Outside Services represents consulting and contractor services. Finance engages external consultants to provide specialized services not available internally. These services include but are not limited to specialized audit work, financial reporting, pension reporting, tax consulting, enterprise risk management advisory and guidance services. These costs are budgeted at approximately $415 thousand lower in 2014 vs. 2013 or a 47% decrease, as it is expected that there will a reduction in the utilization of external consultants.

21. Audit fees represent the annual costs related to the annual audit (including quarterly reviews) of the Company's financial statements and internal controls certification. These fees are direct fees charged by the Company's External Auditors and may fluctuate based on several factors, however these fees are budgeted to increase with the rate of inflation.

22. Other expenses include costs related to memberships, employee services and development, and materials and supplies.

23. Cost charged to affiliates represents cost recoveries related to work performed by the Finance department for other affiliate companies. The Finance Department performs services on behalf of other affiliates including financial services, audit services, accounting and tax services. In 2013, six EGD employees are working full time on an enterprise project – the Finance Renewal Project ("FRP"). FRP is an

important initiative that will transform the core financial processes of the Company. FRP will allow Finance to enhance the value it provides, provide new opportunities for employees and make better use of technology. The targeted outcomes are: (1) Improve efficiency with better tools and processes; (2) Provide more business insight with the right skills and information; (3) Provide the ability to scale for growth and reduce risk; and (4) Provide work / life balance for employees. In essence FRP will provide new technology and tools (enhanced systems) for financial reporting and analysis, streamline processes, increase automation where possible and allow the organization to provide increased services while keeping staffing costs stable and improving efficiency.

Productivity

24. The Finance Department is expected to have a total FTE complement of 130, 125 and 125 in the years 2014 to 2016 in 2013, resepectively. This reduction in FTEs will be achieved through attrition and restructuring to become more effective and efficient, or in other words, more productive. One of the ways Finance will do this is through the use of new / enhanced systems which will allow Finance to provide at least the same amount of services (if not more) to a growing business with a reduced FTE compliment. This in turn results in a reduction in the amount of O&M costs to support the staff complement. From 2013 to 2016, the supporting Finance Department O&M costs are reduced by 14%.

Variance Explanations 2014 Budget versus 2013 Budget

25. The 2014 Budget is higher than 2013 Historic by $0.3 million as shown in Table 2. It is primarily driven by a reduction in recovery from affiliates of $1.0 million which is partially offset by a reduction in salaries and wages of $0.3 million and outside services of $0.4 million.

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

26. The reduction in recoveries from affiliates is due to less time being spent on an enterprise project by Company employees in 2014 versus 2013. In 2014, phase 1 of FRP will be implemented; as a result, three EGD employees assigned to the project will be rolling off the project, resulting in reduced affiliate recoveries.

27. Net salaries and wages are lower in the 2014 budget versus 2013 historic as a result of FTE reductions, which is partially offset by a 2.5% increase in overall wages and salaries.

28. 2014 FTE's are lower than 2013 by three FTE's as there will be an FTE reduction via attrition and the realization of productivity efficiencies.

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

Finance Department
O&M by Expense Type - 2014 vs. 2013
Table 2

Line No.	O&M Costs ($000's)	2014 Budget	2013 Budget	Variance
1	Salaries and Wages	11,431	11,775	(343)
2	Capitalization	(1,562)	(1,499)	(63)
3	Net Salaries & Wages	9,870	10,276	(406)
4	Travel and Entertainment	559	601	(41)
5	Outside Services	464	879	(415)
6	Other	235	240	(5)
7	Audit Fees	1,616	1,594	22
8	Sub-total	12,745	13,589	(845)
9	Internal Recoveries	(1,027)	(2,136)	1,109
10	Total Finance	11,717	11,453	264
11	FTE	130	133	(3)

Variance Explanations 2015 Budget versus 2014 Budget

29. The 2015 Budget is higher than the 2014 Budget by $0.3 million as shown in Table 3. It is primarily due to a reduction in recoveries from affiliates of $0.5 million partially offset by a reduction in net salaries and wages of $0.2 million.

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

Finance Department
O&M by Expense Type - 2015 vs. 2014
Table 3

Line No.	O&M Costs ($000's)	2015 Budget	2014 Budget	Variance
1	Salaries and Wages	11,269	11,431	(162)
2	Capitalization	(1,607)	(1,562)	(45)
3	Net Salaries & Wages	9,662	9,870	(207)
4	Travel and Entertainment	525	559	(35)
5	Outside Services	441	464	(23)
6	Other	239	235	4
7	Audit Fees	1,643	1,616	27
8	Sub-total	12,510	12,745	(235)
9	Internal Recoveries	(531)	(1,027)	496
10		11,979	11,717	262
11	FTE	125	130	(5)

30. The reduction in recoveries from affiliates is due to the conclusion of an enterprise wide project in 2014, which three Finance staff were assigned to on a full-time basis.

31. The reduction in net salaries and wages in the 2015 budget versus the 2014 budget is due to a reduction in FTE's from 130 to 125, which is partially offset by an overall 2.5% increase in salaries and wages.

<u>Variance Explanations 2016 Budget versus 2015 Budget</u>

32. The 2016 Budget is higher than the 2015 Budget by $0.3 million as shown in Table 4. It is primarily due to an increase in net salaries and wages of $0.3 million,

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

as a result of a 2.5% overall increase in salaries and wages, while all other costs are contained at less than inflationary increases.

Finance Department
O&M by Expense Type - 2016 vs. 2015
Table 4

Line No.	O&M Costs ($000's)	2016 Budget	2015 Budget	Variance
	Salaries and Wages	11,592	11,269	323
	Capitalization	(1,653)	(1,607)	(46)
	Net Salaries & Wages	9,940	9,662	277
	Travel and Entertainment	488	525	(36)
	Outside Services	444	441	2
	Other	243	239	4
	Audit Fees	1,671	1,643	28
	Sub-total	12,786	12,510	276
	Internal Recoveries	(535)	(531)	(4)
		12,251	11,979	272
	FTE	125	125	-

Witnesses: S. Chhelavda
S. Kancharla
B. Yuzwa

O&M - LAW DEPARTMENT

Mandate and Responsibilities

1. The Law Department (the "Law Department" or "Law") is responsible for the delivery of legal and corporate secretarial services to Enbridge Gas Distribution Inc. (the "Company") and a number of its affiliated and subsidiary companies. The Law Department directly provides a wide range of legal services through its own internal resources, which include seven lawyers and two law clerks. In addition, the size and complexity of the Company's regulated business requires significant use and management of external legal resources, to supplement the department's direct in-house work. Law is also responsible for: (1) Corporate Security, which is charged with maintaining proper security arrangements for the Company's employees, facilities and assets, described further below in paragraph 7; and (2) Records Management, which is described below in paragraphs 8 to 10.

Services and Activities - Legal Services

2. The Law Department delivers legal services primarily within the following areas: employment/labour law (including workplace safety issues), corporate/commercial law, corporate governance (including corporate secretarial services, and securities law advice related to the Company's continuous disclosure obligations), dispute and litigation management, administrative and regulatory law, ethical, legislative and regulatory compliance matters arising from the Company's duties under the *Technical Standards and Safety Act* and other public safety statutes, information technology and intellectual property law, pension/benefits law and privacy law. Services are provided through a combination of internal and external law firm lawyers, law clerks and administrative staff. Law is also responsible for negotiating and managing retainer arrangements with certain Ontario-based law firms that deliver legal services to the Company.

3. The Law Department frequently works with other Enbridge Inc. ("EI") law departments to ensure continuing access to legal, corporate secretarial, security, records management and other applicable industry leading practices. Through its relationship with professional staff and resources in other EI law departments, the Law Department is provided access to legal research, precedents, policies, applications and expertise, thereby avoiding some external legal costs. A further benefit of the Law Department's relationship with other EI law departments is the fact that the Company enjoys favourable retainer arrangements with two top-tier national law firms on terms that reflect the volume of legal services provided by these firms to all Canadian-based Enbridge businesses.

4. Commencing with the Company's 2011 fiscal year, the Law Department assumed responsibility for the oversight and management of a consolidated budget for external legal services delivered to the Company, with some exceptions. Previously, individual Company departments were responsible for the maintenance of their own budgets for external legal services. The consolidated legal services budget that now falls within the Law Department's responsibility is forecast to be approximately $2.76 million for 2014, $2.82 for 2015 million and $2.89 million in 2016. However, other legal fees for things such as the Manufactured Gas Plant issue and Ontario Hearing Costs are not included within the Law Department's consolidated external legal fees budget.

5. The Company continues to implement improvements to its compliance and governance environment, due in part to legislative and regulatory requirements in the areas of privacy law, new anti-spam laws, occupational health and safety law, Accessibility for Ontarians with Disabilities and consumer protection law and with respect to enhanced operational, environmental and safety requirements under various laws and regulations. A lawyer was hired in the second half of 2012 to help

reduce external legal costs related to pre-litigation disputes, litigation management, compliance reporting and regulatory matters.

6. Additionally, the need for more robust internal supplier management controls was identified by the Company and the resulting process improvements have led to the assumption of additional oversight responsibilities by the Law Department. The Contracts Selection, Review and Administration Policy ("CSRAP"), introduced in 2008, has led to a significant increase in contracts work (including contract review, drafting and post-execution administration). The Law Department has also been involved with the implementation of improvements to the Company's procurement practices, including the development of policies and the delivery of advice targeted to improve the Company's overall approach to the management of external contractors. Each of these initiatives is intended to systemically reduce contracting and procurement risk for the Company and, ultimately, drive better value out of the resulting business relationships.

Services and Activities - Corporate Security Services

7. The Law Department is responsible for the delivery of Corporate Security services to the Company and certain affiliated and subsidiary corporations. Corporate Security services include: (i) the development of effective countermeasures identified as a result of strategic risk management planning, (ii) conducting investigations into employee, supplier or customer misconduct, (iii) developing and delivering education and awareness programs, (iv) crisis management services, and (v) providing ongoing assessments of potential vulnerabilities in the Company's and certain affiliates' security systems and programs. The functions and staffing composition of the Law Department's Corporate Security component have evolved to adapt to environmental changes and the introduction of new regulatory requirements.

Services and Activities - Records Management

8. Since 2011, the Law Department has been responsible for implementation of the Company's Records Management governance function. The need for in-house Records Management resources was identified as a result of reviewing the Company's business environment and consultations with other EI departments, in order to ensure that the Company is positioned to adhere to leading practices for document management and records discovery. Additionally, safety imperatives, regulatory pressures and business demand for professional records management services from within the Company also create a need for the in-house Records Management function.

9. Records Management is responsible for developing, implementing and maintaining policies, procedures, guidelines and standards that establish principles and rules for the management of both official records and transitory material, including creation and/or capture, active use and distribution, inactive retention and final disposition. Records Management services include implementing Records Management practices and tools within business processes, creating awareness, auditing compliance with both the Company and Corporate Records Management policies and supporting legal discovery processes.

10. The Records Management function supported by the Law Department also maintains a modest budget (approximately $130,000 in 2014) for consulting services to assist with implementing Records Management practices (such as the performance of field assessments and the delivery of services and advice related to the management and disposition of inactive records) in accordance with the Company's Records Management policies, standards and guidelines.

2013 – 2016 Budget

11. The Company is planning to implement several major projects over the 2013-2016 period. These projects, which include major gas distribution system reinforcements and significant technology system implementations, will involve intensive internal legal services to support the desired outcomes for each project.

Table 1
Law Department Budgets for 2013 - 2016
($ Thousands)

No.		2013 Budget	2014 Budget	2015 Budget	2016 Budget
1	Salaries and Wages	$ 1,984	$ 2,030	$ 2,075	$ 2,122
2	External Legal Costs	2,700	2,759	2,821	2,885
3	Outside Services	369	308	313	313
4	Costs Charged to Affiliates	(140)	(80)	(80)	(80)
5	Other	246	236	241	246
6	Total Net Utility O&M Expenses	5,161	5,253	5,370	5,491
7	FTE	18	18	18	18

12. Over the period from 2014 to 2016, salaries and employee-related expenses for the Law Department are budgeted to increase by approximately 2.2%, 2.2% and 2.34% from the prior year.

13. Inflationary pressures account for the projected increases in the Law Department 2014, 2015 and 2016 budget as compared to the Department's 2013 budget. Further opportunities to reduce external legal costs (potentially through additional "in sourcing" to Law Department staff) will be evaluated on an ongoing basis.

<u>2014 Budget</u>

14. The 2014 Budget for Law is approximately $5.3 million as illustrated in Table 1.

15. Total FTEs forecast for the 2014 budget are 18. The Law, Corporate Security and Records Management group consists of both management and supervisory employees. Salaries and wages for these FTEs are $2.0 million.

16. External legal fees are a major component of the 2014 Budget ($2.8 million). The creation of a consolidated budget allows the Law Department to maintain greater oversight of all legal services used by the Company, ensure that internal resources are considered before engaging external counsel and ensure the most appropriate selection of external law firm (in terms of cost and expertise).

17. Outside Services are budgeted to be $0.3 million and relate to external services required by the Records Management and Corporate Security groups.

18. Costs charged to affiliates are budgeted to be approximately $0.1 million. Legal and Corporate Security services are provided to affiliates, such as Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited and St. Lawrence Gas Company, Inc.

19. Other expenses are budgeted to be approximately $0.2 million and include employee training and development, memberships, employee travel, fleet vehicles for Corporate Security and office materials and supplies.

Variance Explanations – 2014 Budget

Table 2

2014 Budget versus 2013 Budget
($ Thousands)

No.		2014 (a)	2013 (b)	Variance
1	Salaries and Wages	$ 2,030	$ 1,986	$ 44
2	External Legal Costs	2,759	2,700	59
3	Outside Services	308	369	(61)
4	Costs Charged to Affiliates	(80)	(140)	60
5	Other	236	246	(10)
6	Total Net Utility O&M Expenses	5,253	5,161	92
7	FTE	18	18	0

20. The 2014 Budget is $0.9 million higher than the 2013 Budget, as illustrated in Table 2 principally due to adjustments to salaries and wages and external legal costs which have been increased by 2.2% to account for inflation.

Variance Explanations - 2015 Budget

Table 3

2015 Budget versus 2014 Budget

($ Thousands)

No.		2015 (a)	2014 (b)	Variance
1	Salaries and Wages	$ 2,075	$ 2,030	$ 45
2	External Legal Costs	2,821	2,759	62
3	Outside Services	313	308	5
4	Costs Charged to Affiliates	(80)	(80)	(0)
5	Other	241	236	5
6	Total Net Utility O&M Expenses	5,370	5,253	117
7	FTE	18	18	0

21. The 2015 Budget is approximately $0.1 million greater than the 2014 Budget, as illustrated in Table 3.

22. The 2015 salaries and wages budget is $0.05 million higher than the 2014 budget, due to a salary increase of about 2.2%.

23. External legal fees and outside services will be subject to inflationary increases.

Variance Explanations - 2016 Budget

Table 4

2016 Budget versus 2015 Budget

($ Thousands)

No.		2016 (a)	2015 (b)	Variance
1	Salaries and Wages	$ 2,122	$ 2,075	$ 47
2	External Legal Costs	2,885	2,821	64
3	Outside Services	318	313	5
4	Costs Charged to Affiliates	(80)	(80)	(0)
5	Other	246	241	5
6	Total Net Utility O&M Expenses	5,491	5,370	121
7	FTE	18	18	0

24. The 2016 Budget is approximately $0.1 million more than the 2015 Budget, as illustrated in Table 4.

25. The 2016 salaries and wages budget is $0.05 million higher than the 2015 budget, due to a salary increase of about 2.3%.

26. External legal fees and outside services will be subject to inflationary increases.

Productivity

27 Throughout 2013 to 2016, the Law Department will continue to meet its core mandates and functions through increased focus on internal productivity. The Law Department will continue to examine opportunities to find productivity gains, including

in-sourcing greater amounts of routine or recurring legal work, where a compelling business case and available resources both exist.

O&M BUDGET - OPERATIONS

1. This exhibit outlines the Company's Operations Department's O&M budget for the 2014, 2015 and 2016 fiscal years.

2. The Operations Department at Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") is responsible for the safe and reliable delivery of natural gas to over 2.0 million customers. The distribution system that serves these customers consists of more than 74,000 km of mains and services. To ensure the safe and reliable delivery of natural gas to Enbridge's customers, the Operations Department is required to execute on construction, operation and maintenance work for the distribution system assets. In carrying out this mandate, the Operations Department must ensure that all regulatory compliance, condition monitoring programs and associated maintenance work, emergency response and other miscellaneous operation and maintenance work are all completed with due concern for worker, public and process safety.

3. In order to assist in the achievement of this mandate, the Operations group has gone through a number of organizational adjustments over the past 2-3 years in an effort to clarify and focus on the execution of activities associated with the construction, operation and maintenance of the physical assets comprising the natural gas distribution and underground storage facilities. The purpose of this evidence is to show the activities in the Operations Department and its O&M budget from 2014 to 2016 compared to the 2013 Budget.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

Department Structure

4. At a high level, the Operations Department is organized into Distribution Operations, Storage Operations, System Operations, Operations Safety and Operations Governance & Control.

Distribution Operations

5. The overall goal of Distribution Operations is to ensure safe and reliable operation of the distribution system and reduce operational risk to workers, customers and the public. Activities of the Distribution Operations group include the responsibility for emergency response, meter exchanges, inspection of new appliances, locking and unlocking of meters, as well as other customer generated work such as alterations to gas service installations and relocation of meters. Distribution Operations also perform planned maintenance requirements generated by regular condition monitoring surveys. Meter exchanges, inspections, locks, unlocks, meter work and other customer related work, accounts for over 300,000 units of work per year. Distribution Operations work activities include travel of approximately 15 million km per year.

6. During 2012, the Distribution Operations group was restructured from the traditional "Regional" or geographically based organization, into a more focused "Functional" structure. This functional organization enabled a more streamlined and consistent operation where the various operational functions across the regions were under the direction of a single Director, accountable for all aspects of their function across the Enbridge franchise. These functional areas are:

- Connections and Construction - accountable for the logistics of attaching new customers, as well as the construction and installation of all mains and services.

Connections and Construction is also accountable for the replacement of mains and services to maintain the safety and integrity of the distribution system, and the relocation of mains and services as required by municipalities or other authorities.

- Customer Service & Compliance - accountable for the safety and compliance of Enbridge's customers through inspection of appliances, customer equipment warning tag management, gas meter management including exchanges, locks and unlocks, as well as emergency response to reported leaks and incidents.

- Asset Renewal and Improvement - accountable for ensuring the safe operation and integrity of distribution plant, including mains, services, valves and other associated appurtenances. This is accomplished through the execution of maintenance and inspection programs, and the associated repairs or renewal of infrastructure to ensure compliance with all applicable policies, procedures, codes and standards. Worker and public safety is ensured through timely and effective emergency response and repair of distribution system leaks and excavation damages.

- Network Operations - accountable for the overall monitoring and operation of the distribution system, including the pressure control and monitoring stations and equipment. This involves managing and executing the operation and maintenance of pressure control, gas measurement, gas odorization and heating equipment at Enbridge facilities as well as the SCADA system.

- Logistics and Performance - accountable for the administration and safe operation and maintenance of the Enbridge fleet comprising over 750 vehicles and 300 pieces of heavy equipment, as well as the safe and efficient operation of the Enbridge warehouses.

Storage Operations

7. Storage Operations is responsible for the design, construction, operations and maintenance of all of the underground gas storage facilities owned by Enbridge. Most of this is located in Lambton and Kent counties in what is known as the Tecumseh system, however, there is also a small storage pool (Crowland) in the Niagara Region. Components that comprise the underground gas storage facilities include wells or “down-hole”, pipelines and compressor plants. Down-hole facilities include the well casings into the formations, well heads, valves and associated piping at the surface. Pipeline facilities include well head laterals, gathering lines and pipelines that bring the gas from the storage pools to the plot edge of the compressor plants. Compressor plant facilities include all of the components from the plot edge into and within the compressor plant, including plant piping, valves, meters, compressors, and associated equipment and instrumentation. The Tecumseh system currently operates about 119.3 PJ (3,175.4 10^6m^3) of working capacity storage, of which13.9 PJ (370 10^6m^3) is unregulated.

System Operations

8. System Operations is a support group for the Distribution Operations group and is primarily focused on execution of the information systems and processes associated with the planning and scheduling of work in the field. The Work Management Center handles activities related to the planning, initiation, follow up and completion of work. The Operations Solutions group handles the systems/process issues and enhancements related to the work management system.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

Operations Safety

9. The Operations Safety group (also referred to as Employee Health and Safety or "EHS") has overall responsibility for the environment, health and safety activities of the Company, including development, implementation and effective monitoring of an EHS management system to protect the health and safety of all employees. The group identifies EHS training and educational needs and develops communication tools to ensure that information and knowledge is provided to allow employees to safely fulfill their responsibilities. The group liaises with the Ministries of Labour, Environment and Energy, and other government agencies including the Workplace Safety and Insurance Board, to represent interests of the Company. The group provides information, advice, and direction to the organization regarding the interpretation of requirements and the application of environmental and occupational health and safety legislation, guidelines, codes, and best practices. It also provides managers, supervisors and staff with assistance, direction, support and tools to assist them in achieving EHS compliance and determining best practices.

Operations Governance & Control

10. Operations Governance & Control provide oversight to the overall financial, operational and compliance areas within Operations. This includes ensuring that the goods and services procurement, ongoing construction, operation & maintenance and emergency response are carried out safely, with high quality, consistently, efficiently and in compliance with all Company and Regulatory Codes, Standards, Policies and Procedures. This is managed through adherence to documented processes, Company procedures, Operator Qualification and training, and compliance for employees and contractors, in addition to the execution of a

comprehensive quality assurance program for all of the functional areas mentioned above, operational audits and reporting.

2013-2016 O&M Budget

11. Table 1 below summarizes the Operations Department's O&M budget for 2013 through 2016. The budget is a consolidation of the requirements of the five individual groups which make up the Operations Department.

Table 1
Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
From 2013 to 2016 Budget

Dept: OPERATIONS

Line No.	Particulars ($000's)	Buget 2013	Buget 2014	Buget 2015	Buget 2016
1.	Gross Salaries and Wages	$ 84,447	$ 86,305	$ 88,724	$ 91,144
2.	Capitalization of Salaries and Wages	(52,062)	(52,873)	(54,245)	(55,625)
3.	Employee Training and Development	370	376	381	386
4.	Materials and Supplies	2,916	2,956	2,997	3,039
5.	Outside Services	26,345	27,133	27,512	27,899
6.	Consulting	2,315	2,347	2,380	2,413
7.	Repairs and Maintenance	2,160	2,190	2,221	2,252
8.	Fleet	9,354	9,484	9,615	9,749
9.	Rents and Leases	2,089	2,119	2,148	2,178
10.	Telecommunications	25	25	26	26
11.	Travel and Other Business Expenses	1,034	1,048	1,062	1,077
12.	Memberships	211	214	217	220
13.	Internal Allocations and Recoveries	(16,740)	(16,972)	(17,208)	(17,447)
14.	Other	1,430	1,450	1,470	1,490
15.	Total Net Utility O&M Expense before Eliminations	63,894	65,800	67,300	68,800
	FTEs	1,208	1,208	1,208	1,208

12. Of the total Operations Department O&M budget each year, approximately 66% is for Distribution Operations; 14% is for Storage Operations; 9% is for System

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

Operations; 8% is for Operations Safety; and 3% is for Operations Governance & Control.

13. Budget requirements within Distribution Operations, which account for approximately 2/3 or 66% of the overall budget within Operations, are driven by items such as compliance work as mandated by industry and Company codes, standards and procedures; customer growth and expectations; general system maintenance and operations; execution of system improvements and system integrity and reliability work; metering requirements; worker safety; and third party issues such as leaks and damages.

14. Budget requirements within Storage Operations, accounting for approximately 14% of the overall Operations budget, are driven by similar items to Distribution Operations, including compliance, ongoing maintenance and system improvements, and system integrity and reliability activities.

15. Compliance, customer requirement and system improvements also impact the budget requirements of the other groups within the Operations Department, as those groups support the processes required to execute the work in the field.

16. The primary components of cost within the Operations Department are labour, including internal salaries and wages at approximately 50%, along with contractor costs for the execution of work in the field ("Outside Services") at approximately 40%. These costs are subject to inflationary pressures common to other employment-related costs.

17. In addition to inflation, the cost pressures experienced by the Operations Department also arise from growth in mandate and activities. The continuation of

the historic activities of the Operations Department, along with increasing expectations and responsibilities, dictate that the level of internal resources (FTEs) and Outside Services should increase, and at very least must not be reduced from past levels. Given the Company's decision to freeze staffing levels from 2014 to 2016, this will be a challenge.

Cost Drivers

18. As explained, the Operations Department is charged with a wide range of responsibilities and expectations. Each day, the Operations Department interacts with thousands of customers and works to meet these customer's expectations. The expansion and infill of customers on the distribution system will naturally drive increases in both customer driven and Company driven compliance work including inspections, turn-ons, meter work, tags etc. With steady customer growth over the past several years (10% in the past 5 years for example), this is expected to continue through the 2014-2016 term with upwards of over 36,000 customer additions forecast annually. Other sources of increased work requirements for the Operations Department arise from an aging infrastructure and heightened compliance and worker safety requirements and expectations.

19. While many of these responsibilities are not new (such as system maintenance, customer attachments, metering, worker safety training and so on), the requirements in many areas are increasing.

20. In order to emphasize the increased requirements that the Operations Department must accommodate, the following sections detail some of the emerging and growing cost drivers that the Operations Department expects to be facing in the 2014 to 2016 term.

Customer & Public Safety

21. While customer growth continues, the Company has seen the expectations from customers increasing, and has taken a number of steps to address and meet these increasing expectations, such as requiring service technicians to call customers to let them know they are on their way to meet customer appointment. Enbridge provides materials to customers at the end of each service appointment to help educate customers on natural gas safety and explain and help them understand what work has taken place in their home or business.

22. Customer safety enhancements have also been achieved through safety assessments for targeted high risk sectors within Enbridge's customer base to help educate customers on the safe use of natural gas and reminding them that all gas firing equipment should be regularly maintained. As part of the assessment, an inspection takes place that identifies areas that must be addressed at the premise to ensure the safe operation of the equipment and ultimately, the safety of the customer.

23. The Company has made a number of improvements to enhance the safety of both customers and employees through research and industry leading practices. Reducing response time on emergency calls reduces risk to the public, enabling trained personnel to respond, take action and make the area safe in a timelier manner. Enbridge has recently improved emergency response times from 90% within 60 minutes; to 90% within 45 minutes for all emergency calls. In keeping with industry standards for emergency response, the Company has implemented the Incident Command System ("ICS") structure into its operations. This is a standard amongst first responder agencies, including Police and Fire and is

instrumental in improving Enbridge's overall and coordinated response to gas distribution emergencies, such as fires, third party damages, etc.

24. Similar improvements have also been achieved in the response and completion of distribution system leak repairs, reducing the risk to the public. Safe excavation practices, particularly in the vicinity of buried gas plant, including the increased use of hydro-vac has helped to minimize excavation damage, improving worker and public safety. Continuous improvement in safety performance has been achieved through the implementation of industry leading practices and procedures.

Worker Safety

25. Externally imposed requirements through the Ministry of Labour have been implemented across Ontario, limiting the hours of work that a worker can carry out during prescribed time periods. While this serves to increase worker safety, it causes upward cost pressures in situations where extended hours may be required to complete jobs such as emergency response repairs or deadline driven or large construction and maintenance projects where customer commitments are to be met.

26. The Company is continuing its focus upon reducing, and ideally eliminating worker safety events and public safety events. This goal of eliminating such events is aspirational, but is useful to assist the workforce to think differently about their safety, their colleague's safety, and the public's safety, and to drive a step change in safety performance. Ultimately, Enbridge aims to systematically reduce and/or eliminate exposure to hazardous situations.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

System Integrity & Reliability

27. As a result of recent incidents in the oil and gas industry, there is a heightened level and new standard of scrutiny on focusing on mitigating risks and minimizing the potential for significant events. Enbridge will continue the development and integration of the eleven elements of Process Safety Management (PSM) into key business processes to drive improved risk management to prioritize and mitigate key risks related to the Company's assets and their operation. The Company will strengthen current efforts and augment them with a targeted PSM program and initiatives.

28. As Enbridge's infrastructure ages, ongoing and increasing maintenance is required. Significant parts of the distribution system was originally built during the introduction of natural gas to Ontario in the late 1950's and is now 50 to 60 plus years of age. As this system ages, additional maintenance is required to ensure the integrity and reliability of the system.

29. Many of the activities identified within the System Integrity and Reliability Capital Budget will drive a need for additional training, and will result in incremental maintenance work. For example, while the increase In-Line Inspection ("ILI") of pipelines is a very important and valuable activity, the inspection tools disrupt and move the internal debris within the pipeline system, resulting in increased wear on valves and regulation station components and increased buildup in filters. This creates a need for increased frequency of maintenance and component change out, filter removal and cleaning, or replacement.

30. As the pipeline infrastructure ages and with growth becomes even more utilized, gas distribution companies need to operate, inspect and maintain their assets with

greater rigor to assure continued safety and reliability. One of the areas that Industry is embracing to enhance the reliability and safety of the gas network, is in the area of 'situational awareness', or providing centralized oversight on the status and activity underway on the distribution system at any given time. Enbridge has developed a network monitoring initiative to plan, permit, and monitor the work and effects on its pipeline network to enhance situational awareness. By maintaining situational awareness of the work on the Company's pipeline network, it is expected that safety and reliability will be maintained through avoidance of higher risk activities which could potentially cause safety events or outages to key parts of the system.

Compliance and other external factors

31. After certain high profile events in the United States, Industry and Regulatory bodies have reviewed the need for reduction of risk in areas of high consequence. The recent TSSA code adoption document amends CSAZ662-11 and requires the company to identify High Consequence Areas (HCA's), and to address risks in those areas. Acceptable remedial measures include shorter inspection intervals (ILI, Corrosion etc), the possible installation of emergency flow restricting devices (remote operated valves, automatic shut off valves as applicable), increased system monitoring in addition to additional training to personnel on response procedures, conduct drills with emergency responders, and adopting other management controls.

32. Other work is driven by external agencies or factors that are largely uncontrollable by Enbridge. Examples of this include the relocation of pipelines to accommodate new roads, public transit expansion or changes to other utility infrastructure; Measurement Canada inspection and exchange of gas meters, the number of

which is based on statistical techniques and the number of errors identified in a sample of meter population; the issuing and monitoring of "Warning Tags", applied to customers' appliances when safety problems are identified that are not immediately hazardous; locking and unlocking of customers' meters for safety, non-payment of bills or change of occupancy; and finally emergency response to customer equipment failure, fires, pipeline leaks and damages caused by third party excavation around pipelines.

Operations Department O&M Budget Variance Explanations

33. As seen in Table 2, below, the Operations Department O&M budget will increase by $1.9M or 3% from 2013 to 2014, mainly driven by inflation. The Company has forecast that the required level of activity through the Department will be at least as high in 2014 as in 2013. Some of the drivers of the increased activity are detailed above. Notwithstanding the expectation of higher activity, this budget is forecast to increase by an amount only marginally higher than the expected inflation rate. The primary reason for cost increases above inflation is the expectation that contractor rates (which account for around 40% of the budget) will increase by between 3% and 6%.

Table 2
Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
Operations 2013 to 2014 Budget

Line No.	Particulars ($000's)	Buget 2014	Buget 2013	2014 vs. 2013
1.	Gross Salaries and Wages	$ 86,305	$ 84,447	$ 1,858
2.	Capitalization of Salaries and Wages	(52,873)	(52,062)	(811)
3.	Employee Training and Development	376	370	5
4.	Materials and Supplies	2,956	2,916	41
5.	Outside Services	27,133	26,345	788
6.	Consulting	2,347	2,315	32
7.	Repairs and Maintenance	2,190	2,160	30
8.	Fleet	9,484	9,354	130
9.	Rents and Leases	2,119	2,089	29
10.	Telecommunications	25	25	0
11.	Travel and Other Business Expenses	1,048	1,034	14
12.	Memberships	214	211	3
13.	Internal Allocations and Recoveries	(16,972)	(16,740)	(233)
14.	Other	1,450	1,430	20
15.	Total Net Utility O&M Expense before Eliminations	65,800	63,894	1,906
	FTEs	1,208	1,208	(0)

34. As seen in Table 3, below, the Operations Department O&M budget will increase by $1.5M or 2.3% from 2015 to 2014, mainly driven by inflation. As detailed above, the Company expects the work requirements for the Operations Department will continue to grow throughout the IR term. There will be no FTE additions, as part of the Company's productivity efforts (described below) to manage workload within the current FTE base and maintain O&M costs.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

Table 3
Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
Operations 2014 to 2015 Budget

Line No.	Particulars ($000's)	Buget 2015	Buget 2014	2015 vs. 2014
1.	Gross Salaries and Wages	$ 88,724	$ 86,305	$ 2,419
2.	Capitalization of Salaries and Wages	(54,245)	(52,873)	(1,371)
3.	Employee Training and Development	381	376	5
4.	Materials and Supplies	2,997	2,956	41
5.	Outside Services	27,512	27,133	379
6.	Consulting	2,380	2,347	33
7.	Repairs and Maintenance	2,221	2,190	30
8.	Fleet	9,615	9,484	132
9.	Rents and Leases	2,148	2,119	29
10.	Telecommunications	26	25	0
11.	Travel and Other Business Expenses	1,062	1,048	15
12.	Memberships	217	214	3
13.	Internal Allocations and Recoveries	(17,208)	(16,972)	(236)
14.	Other	1,470	1,450	20
15.	Total Net Utility O&M Expense before Eliminations	67,300	65,800	1,499
	FTEs	1,208	1,208	0

35. As seen in Table 4, below, the Operations Department O&M budget will increase by $1.5M or 2.2% from 2016 to 2015, again mainly driven by inflation. As detailed above, the Company expects the work requirements for the Operations Department will continue to grow throughout the IR term. As in 2015, there will also be no FTE adds in 2016, as part of the Company's productivity efforts (described below) to manage workload within the current FTE base and maintain O&M costs.

Table 4
Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
Operations 2015 to 2016 Budget

Line No.	Particulars ($000's)	Buget 2016	Buget 2015	2016 vs. 2015
1.	Gross Salaries and Wages	$ 91,144	$ 88,724	$ 2,420
2.	Capitalization of Salaries and Wages	(55,625)	(54,245)	(1,381)
3.	Employee Training and Development	386	381	5
4.	Materials and Supplies	3,039	2,997	42
5.	Outside Services	27,899	27,512	387
6.	Consulting	2,413	2,380	33
7.	Repairs and Maintenance	2,252	2,221	31
8.	Fleet	9,749	9,615	134
9.	Rents and Leases	2,178	2,148	30
10.	Telecommunications	26	26	0
11.	Travel and Other Business Expenses	1,077	1,062	15
12.	Memberships	220	217	3
13.	Internal Allocations and Recoveries	(17,447)	(17,208)	(239)
14.	Other	1,490	1,470	20
15.	Total Net Utility O&M Expense before Eliminations	68,800	67,300	1,501
	FTEs	1,208	1,208	0

Productivity

36. Productivity savings can be seen within the Operations Department O&M budget in a number of ways.

37. A key productivity saving will result from the Company's decision to freeze the number of FTEs though the 2014 to 2016 period, and keep the costs of Outside Services relatively flat. This will lead to clear productivity gains (doing more with the same resources) taking into account the fact that, as detailed in the Cost Drivers section above, the demands on the Operations Department are expected to increase over the 2014 to 2016 period.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

38. In order to be able to meet its increasing work requirements without increasing workforce, the Operations Department will need to find productivity and efficiency gains throughout its various operating groups. While the Operations Department has not conclusively identified all the ways that it will do this, the following are some examples of areas that are being targeted.

39. The Company expects to find and implement improvements in Operations activities through the increased use of technology and process improvements. These improvements will be targeted to address customer, safety and compliance aspects of Operations work.

40. Customer productivity improvements are being analyzed from both a technology and process improvement perspective. The development and implementation of GPS in the field are improving customer commitment schedules and times by enabling the Operations groups to better track locations and progress of the crews in the field. Similarly by improving the process between planning, scheduling and executing the work through organizational and process related activities, both customer commitment schedules and customer satisfaction are improved.

41. Worker and public safety enhancements are being realized through productivity improvement initiatives through expansion of trenchless excavation technologies, which also aid to reduce the size and time to complete and reinstate distribution system excavations. The use of GPS in vehicles has also provided both technology and process improvements in emergency response, enabling the locations of field forces to be pin pointed, reducing the time to respond, as discussed above.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

42. The planning, scheduling and execution of compliance work is being improved through the use of GPS technology. Planning the workload based on locations and matching this up with the resources to complete the work has helped to ensure compliance work is matched up with either customer or routine maintenance work, maximizing efficiency and labour utilization. Organizational adjustments, including the recent functional structure changes in Distribution Operations has improved work flow and reduced duplication and re-work to better balance the available workforce with the increasing workload requirements.

43. The Gas Storage Department has continued to find efficiencies within its operations. The purchase of various specialty tools that had previously been provided by contractors at a high cost (eg snubbing tool) is an example of this, as are drilling horizontal replacement wells and the Company's new Land Lease system.

44. Further productivity options will be explored throughout the IR term.

Witnesses: J. Alton
D. Dalpe
D. Lapp
M. Wagle

2014 to 2016 O&M BUDGET - INFORMATION TECHNOLOGY DEPARTMENT

Mandate and Responsibilities

1. The Information Technology ("IT") Department is responsible for supporting all hardware, software and network and communications infrastructure for Enbridge Gas Distribution Inc. ("Enbridge" or the "Company"). These technologies provide the Company with the ability to execute utility operations, customer care, market development, pipeline integrity, finance, human resources, payroll, legal, government and public affairs and regulatory functions with fewer staff than otherwise would be required.

Services and Activities

2. IT activities are provided by five groups: Technical Services, Information & Productivity Services, Business Applications, Technology Planning and IT Administration.

3. The Technical Services group is responsible for providing Helpdesk Operations, Desktop Management, and Network Management, Data Centre Operations, Security & IT Risk Management and Change Management.

4. Information & Productivity Services is responsible for the management of the integrity and availability of corporate data and the provisioning of productivity tools such as Microsoft Office and email, collaboration tools and Extranet.

5. The Business Applications group is responsible for Solutions Delivery and for providing reliable and efficient system applications support. The Business Applications group has two focused teams: The Solutions Delivery Team and the Business Applications Support Team. The Solutions Delivery Team is

responsible for the definition and execution of Information Technology related projects. The cost of the Solutions Delivery Team is directly charged to the capital projects that it executes and has no impact on the IT departmental O&M budget. The Business Applications Support Team is responsible for incident management, release management and problem management for the applications they support. The cost of the Business Applications Support Team is included in the O&M budget.

6. The Technology Planning group is responsible for IT Strategic Planning, Technology Life Cycle Management and optimizing all IT investments. This group also ensures that individual IT solutions cost effectively satisfy business needs.

7. The IT Administration group consists of an IT Director and IT Administrator. The IT Director provides Strategic and Operational Leadership for the IT organization.

8. The CIS Hosting and Support cost component has been excluded from the total IT O&M cost budget for periods 2013-2016 as the CIS Hosting and Support cost was settled as part of the Customer Care/CIS settlement agreement (EB-2011-0226). Costs associated with that function are being recovered through the Customer Care/CIS costs, as described at Exhibit D1, Tab 10, Schedule 1.

<u>2014 - 2016 Budget</u>

9. Details of Enbridge's budget, including new initiatives for the budget periods, are set out below in Table 1.

Table 1

IT Department Budget for 2013-2016
(Amount in '000)

Component	**2013 Budget ($)**	**2014 Budget ($)**	**2015 Budget ($)**	**2016 Budget ($)**
Gross Salaries & Wages	14,692	15,015	15,350	15,697
Capitalization of Salaries & Wages	(5,106)	(5,132)	(5,157)	(5,183)
Net Salaries & Wages	9,586	9,883	10,193	10,514
Employee Training & Development	618	632	646	660
Outside Services	15,159	15,376	15,631	19,987
Telecommunications	3,603	3,682	3,764	3,849
Travel & Other Business Expenses	627	641	655	669
Cost charged to Affiliates	(3,745)	(3,827)	(3,913)	(4,001)
TOTAL	**25,848**	**26,387**	**26,976**	**31,678**
FTE	**178**	**178**	**178**	**178**

10. Over the period from 2014 to 2016, salaries and employee-related expenses for IT are budgeted to increase by approximately 2.2% each year.

11. For Outside Services, inflationary pressures account for the projected increases in 2014, 2015. In 2016, the Company plans to internally operate, host and support the Work and Asset Management Solution (WAMS) application similar to the Customer Information System (CIS) application. Therefore, the Company will incur $4.1 million for WAMS hosting and support cost as part of O&M costs in 2016. The reminder of the increase in 2016 is due to inflationary pressures. The WAMS support cost includes internal staff, contractors, telecommunications, hardware and software maintenance. The details of the WAMS project are described at Exhibit B2, Tab 8, Schedule 2.

Witnesses: T. Adesipo
B. Misra

12. Inflationary pressures account for the other projected increases in 2014, 2015 and 2016 budget as compared to the Department's 2013 budget.

<u>2014 Budget</u>

13. The 2014 Budget for IT is approximately $26.4 million as illustrated in Table 1.

14. Net Salaries and Wages for the 2014 Budget of $9.88 million (net of capitalization) include employee salaries. The salaries and wages of the Solution Delivery Team within the Business Applications group are 100% capitalized and directly charged to capital projects.

15. Employee Training and Development for the 2014 Budget of $0.6 million includes costs for training and development for full-time employees within the IT Department. Examples of the training includes Security and Risk Management training to enhance skills and awareness of the IT Security Team to ensure IT continues to be safe and secure, as well as project management, business analysis training to ensure IT projects are managed effectively and aligned with technology direction.

16. Outside Services of $15.4 million for the 2014 Budget represents costs paid to contractors or consultants or outsourcers ($5.5 million) and fees paid to vendors for software and hardware maintenance ($9.9 million). Contractor costs are incurred to perform desktop maintenance activities, augment existing support staff to handle extra workload, to back fill staff seconded to capital projects and to augment support in the early days of a new application going

live. Consultants are engaged from time to time to assist with a particular expertise that the Enbridge IT staff do not possess.

17. Telecommunications expense of $3.7 million includes internet data connections for Enbridge sites, cellular and BlackBerry, office and land phones expenses.

18. Travel and Other Business Expenses of $0.64 million includes travel, membership fees, and stationery supplies, such as tapes used for backup and system recovery purposes.

19. Costs charged to affiliates of $3.83 million represents work performed by IT department support staff from time to time, such as desktops, laptops and servers support services for affiliates such as Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited and St. Lawrence Gas Company, Inc.

2014 Year vs 2013 Budget

20. The 2014 O&M Budget for the IT Department is $26.4 million and the 2013 ADR is $25.8 million. Table 2 on the following page shows the variance between 2014 and 2013 with further explanation in the subsequent sections.

Table 2

IT Department Budget : 2013 vs 2014
(Amount in '000)

Component	**2013 Budget ($)**	**2014 Budget ($)**	**Variance ($)**
Gross Salaries & Wages	14,692	15,015	(323)
Capitalization of Salaries & Wages	(5,106)	(5,132)	26
Net Salaries & Wages	9,586	9,883	(297)
Employee Training & Development	618	632	(14)
Outside Services	15,159	15,376	(217)
Telecommunications	3,603	3,682	(79)
Travel & Other Business Expenses	627	641	(14)
Cost charged to Affiliates	(3,745)	(3,827)	82
TOTAL	**25,848**	**26,387**	**(539)**
FTE	**178**	**178**	**0**

21. Salaries & Wages: The 2014 salaries and wages budget is $0.3 million higher than the 2013 budget, due to a salary increase of approximately 2%.

22. Outside Services: The hardware and software maintenance and contractor costs will increase by $0.2 million due to inflationary pressure.

23. Telecommunications: Telecommunications cost will increase by $0.1 million due to inflationary pressure.

Witnesses: T. Adesipo
B. Misra

2015 O&M Budget vs 2014 Budget

24. The 2015 O&M Budget for the IT Department is $27.0 million and the 2014 Budget is $26.4 million. Table 3 on the following page shows the variance between 2015 and 2014 with further explanation in the subsequent sections.

Table 3

IT Department Budget : 2014 vs 2015
(Amount in '000)

Component	**2014 Budget ($)**	**2015 Budget ($)**	**Variance ($)**
Gross Salaries & Wages	15,015	15,350	(335)
Capitalization of Salaries & Wages	(5,132)	(5,157)	25
Net Salaries & Wages	9,883	10,193	(310)
Employee Training & Development	632	646	(14)
Outside Services	15,376	15,631	(255)
Telecommunications	3,682	3,764	(82)
Travel & Other Business Expenses	641	655	(14)
Cost charged to Affiliates	(3,827)	(3,913)	86
TOTAL	26,387	26,976	(589)
FTE	**178**	**178**	**0**

25. Salaries & Wages: The 2014 salaries and wages budget is $0.3 million higher than the 2014 budget, due to a salary increase of approximately 2%.

26. Outside Services: The hardware and software maintenance and contractor costs will increase by $0.3 million due to inflationary pressure.

Witnesses: T. Adesipo
B. Misra

2016 O&M Budget vs 2015 Budget

27. The 2016 O&M Budget for the IT Department is $31.7 million and the 2015 Budget is $27.0 million. Table 4 shows the variance between 2016 and 2015 with further explanation in the subsequent sections.

Table 4

IT Department Budget : 2015 vs 2016
(Amount in '000)

Component	**2015 Budget** ($)	**2016 Budget** ($)	**Variance** ($)
Gross Salaries & Wages	15,350	15,697	(347)
Capitalization of Salaries & Wages	(5,157)	(5,183)	26
Net Salaries & Wages	10,193	10,514	(321)
Employee Training & Development	646	660	(14)
Outside Services	15,631	19,987	(4,356)
Telecommunications	3,764	3,849	(85)
Travel & Other Business Expenses	655	669	(14)
Cost charged to Affiliates	(3,913)	(4,001)	88
TOTAL	26,976	31,678	(4,702)
FTE	**178**	**178**	**0**

28. Salaries & Wages: The 2014 salaries and wages budget is $0.3 million higher than the 2015 budget, due to a salary increase of approximately 2%.

29. Outside Services: The hardware and software maintenance and contractor costs will increase by $0.3 million due to inflationary pressure.

30. Outside Services: The cost to support and host WAMS of $4.1 million is described in paragraph 11.

Witnesses: T. Adesipo
B. Misra

31. Telecommunications: Telecommunications cost will increase by $0.1 million due to inflationary pressure.

Productivity

32. Throughout 2013 to 2016, IT will continue to meet its core mandates and functions through increased focus on internal productivity. There will be particular challenges arising from the fact that IT Department budgets will only increase by a level of around inflation. While the IT Department has not conclusively identified all the ways that it will do this, as in previous years, IT Department Managers will prioritize achieving cost savings which include negotiations with Vendors to generate savings. Enbridge expects to require, at minimum, the same level of IT support in 2014 and going forward, as it did in previous years.

O&M - BUSINESS DEVELOPMENT & CUSTOMER STRATEGY DEPARTMENT

Mandate and Responsibilities

1. The mandate of the Business Development & Customer Strategy ('BDCS') department is to provide customers with professional and reliable services that enable and enhance their ability to interact with the Company as part of understanding, managing, and paying for natural gas energy usage; and to improve customer satisfaction overall.

2. BDCS department activities fall within two main categories: a) those activities that provide existing customers with cost-effective services such as Billing, Call Centre/Inquiry, Appointment Scheduling, and Energy Efficiency/DSM (Demand Side Management) Programs; and b) those activities that attract new customers or aid existing customers wishing to expand their usage (e.g. industrial expansion). A common unifying theme, whether it be to attract new customers, deliver energy efficiency programs, or assist customers who are considering load expansion, is the goal of maximizing the competiveness and relevance of natural gas, thus lowering costs to customers. In part, this goal requires the Company to remain abreast of technological developments related to the efficiency of end use natural gas equipment and/or competitive developments of alternate energy solutions.

3. The BDCS group is comprised of the following three departments: Customer Care, Market Development & Sales and Business Development. The BDCS department has changed since the 2013 Test Year filing (EB-2011-0354). At that time the BDCS department consisted of the following groups: Customer Care, Market Development, Sales, Conservation Services, Demand Side Management ("DSM"), Business Development, NGT (Natural Gas for Transportation) and Strategy

Research & Planning. In late 2012, Market Development, Sales, Conservation Services, and DSM were consolidated into Market Development & Sales. Similarly, Business Development and NGT were consolidated into Business Development. Finally, in January 2013 Strategy Research and Planning was moved to and consolidated within the Finance Department.

4. The purpose of this evidence is to provide an overview of BDCS, Operating and Maintenance ("O&M") expenses for the three years from 2014 to 2016. As stated in paragraph three, BDCS has 3 main departments: Customer Care, Market Development and Sales and Business Development. A significant portion of Customer Care's O&M budget is not in scope for this filing, and instead is within the scope of the EB-2011-0226 ADR Settlement; and is addressed in Exhibit D1, Tab 10, Schedule 1 and Exhibit D1, Tab 11, Schedule 2.

<u>Customer Care</u>

5. The Customer Care department is responsible for the provision of customer care services in support of the business needs of the Company. Customer Care functions include meter reading, billing, customer contact, collections, credit risk assessment and functional support of the Customer Information System ("CIS"). Additionally, the Customer Care department includes the Direct Purchase group, which is responsible for managing relationships and contracts with large customers; as well as the administration of the Agent Billing & Collection program and the direct purchase program.

6. Customer Care's O&M budget is shown in Exhibit D1, Tab 3, Schedule 1, which is in scope for the EB-2011-0226 ADR Settlement and is addressed in Exhibit D1, Tab 10, Schedule 1, and Exhibit D1, Tab 10, Schedule 2. Other Customer Care

costs not within the scope of the EB-2011-0226 Settlement are addressed separately. The Provision for Uncollectible Accounts is addressed in Exhibit D1, Tab 3, Schedule 1. The O&M costs for the Direct Purchase group are addressed in this evidence and shown in Table 4.

Market Development and Sales

7. The Market Development and Sales ("MD&S") team is responsible for developing and delivering cost-effective programs to design, deliver and promote DSM programs as well as programs that attract new customers to the distribution system. The group also works with certain customer types (typically Industrial or large Commercial) wishing to expand their gas usage.

8. MD&S consists of the following sub groups: Residential Energy Solutions, Commercial Energy Solutions, Industrial Energy Solutions, New Construction Commercial, Market Development and Sales Services, DSM Policy & Evaluation Measurement & Verification ("EMV") and the Sales Enquiry Centre.

9. The Residential Energy Solutions, Commercial Energy Solutions, Industrial Energy Solutions, and Sales Enquiry Centre activities include delivery of energy efficiency and growth programs to the residential, industrial and commercial sectors. This includes initial points of contact with the Company's customers and business partners; support for the customer connection process; and the design and delivery of energy efficiency programs to end users and business partners. A portion of this activity is directly related to the attachment of new customers and is capitalized. This includes employees working directly with new home builders on issues related to attachment along with marketing and outreach efforts to prospective customers (on or near a gas main, but not currently using gas).

As well, the Company maintains a small Sales Enquiry Centre dedicated to responding to prospective customer enquiries related to access to natural gas.

10. The Marketing and Sales Services group provides centralized promotion and communications support for all MD&S programs. The group leverages a variety of channels such as mail, advertising and the Company's website, to promote and inform customers about DSM and new customer growth programs. The group also includes the Business Intelligence and Research team which provides the primary and secondary research and data required to analyze and understand a particular sector or segment before marketing efforts can be developed.

11. The DSM Policy & EMV group manages the administrative and regulatory requirements for the Company's DSM portfolio and related activities, and ensures that all programs designed and delivered by Market Development and Sales meet cost effectiveness requirements. The Company recently filed an application for approval of the updated 2012 DSM Plan for the 2013 and 2014 rate years. The filing was made February 28, 2013 in EB-2012-0394. The updated plan was developed in consultation with regulatory interveners and includes a comprehensive Settlement Agreement.

12. The New Construction Commercial ("NCC") group is composed of staff reporting to the overall MD&S department; however, it is composed almost entirely of staff dedicated to the delivery of the High Performance New Construction ("HPNC") program under contract to the Ontario Power Authority ("OPA") and local electric distribution companies ("LDCs"). Consequently, the NCC group is essentially a standalone unit that does not share or participate in other Company programs with the exception of the cross promotion of the Company's natural gas new

construction DSM programs. Delivery of both CDM and DSM programs to the commercial new construction sector by one organization results in a “one-stop shop” that provides an enhanced customer experience at a lower overall cost. An allocation equivalent to one FTE is transferred from the NCC group to DSM to account for the gas DSM cross sales effort (currently the Commercial Savings by Design program).

13. As HPNC is considered an Electric Conservation Services activity. Overhead costs are included with O&M in accordance with the requirements of EB-2011-0008, Exhibit N1, Schedule 1 as costs and revenues are shared 50/50 within the Electric Program Earnings Sharing Deferral Account (“EPESDA”). HPNC net revenues have been shared in 2011 and 2012. This treatment is expected to continue in 2013 and 2014.

14. The HPNC contract expires at the end of 2014 by which time all projects must be built, evaluated and delivering contracted electricity demand savings. The Company has reflected this expectation in its forecast of Overhead Recoveries, O&M and FTEs starting in 2015 (Lines 6, 9 and 11 of Table 1).

Business Development

15. The Business Development team is responsible for identifying and introducing new energy technologies that can help existing and potential new customers optimize their energy use. This includes identifying new opportunities for energy efficiency and improving energy use through new DSM programs as well as new end use opportunities. . Identifying and promoting new end-use technologies helps both new and existing customers optimize their energy bill and in some cases has other benefits, be it load switching to reduce electricity consumption or other environmental benefits due to shifting demand from more carbon intensive sources

of energy. Customers benefit from these efforts over the long-term through the resulting innovations in energy efficiency technologies and the improved competitive position of natural gas against other fuels and technologies. The Company works closely with other utilities in Canada and across North America for much of this work. Through various research collaboratives, the Company ensures our resources are directed towards commercialization opportunities where new technologies have largely been designed and developed and simply need increased utility support for adoption with end-users. Through these projects Enbridge Gas Distribution ("Enbridge") works with manufacturers to assist in reducing various barriers to adoption, including code requirements, quantifying energy savings benefits and general awareness of new technologies.

16. The Natural Gas for Transportation ("NGT") team is part of the Business Development group and supplies compressed natural gas to transportation customers via six public refueling stations and fuelling equipment installed at the customers' premises. Natural gas remains the cleanest burning alternative transportation fuel, providing a Greenhouse Gas emissions reduction of approximately 20% over traditional gasoline or diesel fuel. In addition to this environmental benefit, natural gas for transportation provides customers with substantive fuel cost savings compared to traditional liquid fuels. Customers using natural gas for transportation include municipal fleet vehicles, medium and heavy-duty vehicles, ice cleaning machines, industrial forklifts and commercial fleet vehicles. Most recently, two garbage collection companies have begun operating refuse trucks on natural gas.

17. Natural gas remains a low-cost vehicle fuel compared to gasoline or diesel fuel, giving a competitive advantage for operators of natural gas vehicles. This has

driven vehicle manufacturers to re-emerge in the production of natural gas powered cars and trucks. By way of example, General Motors and the Ford Motor Company now offer light duty direct natural gas powered vehicles to their customers. Medium duty and heavy duty trucks are also now available from factory Original Equipment Manufacturers (“OEM’s") such as Freightliner, Peterbilt, Mack, and Volvo equipped to operate on compressed natural gas. Engine technology advances by Cummins Westport and Westport Technologies are providing increased penetration into the traditional liquid fuel markets. This provides a new market opportunity for delivery, refuse trucks, and other medium duty and heavy duty vehicle applications to operate on natural gas.

2013 to 2016 O&M Budget for Business Development & Customer Strategy

18. A summary of the 2013, 2014, 2015 and 2016 O&M budgets by major expense type for BDCS excluding Customer Care is presented in Table 1.

Business Development & Customer Strategy
O&M by Expense Type
Table 1

Line No.	O&M Costs ($000's)	2013 Budget	2014 Budget	2015 Budget	2016 Budget
1	Gross Salaries and Wages (net of DSM allocation)	5,724	5,308	5,036	5,153
2	Capitalization	(1,935)	(1,994)	(2,040)	(2,088)
3	Net Salaries and Wages	3,789	3,315	2,996	3,065
4	Employee Development and Travel Expenses	694	704	720	736
5	Program Costs	2,552	2,590	2,646	2,705
6	Internal Allocations and Recoveries	(542)	(423)	-	-
7	Total BDCS Core	6,493	6,185	6,363	6,506
8	Demand-Side Management	31,588	32,159	32,802	33,458
9	Conservation Services	2,728	1,976	-	-
10	Total Business Development & Customer Strategy	40,809	40,320	39,164	39,964
11	Full Time Equivalent (FTE)	132	128	120	120

Note:
1) Business Development and Customer Strategy O&M excludes Customer Care

Witnesses: L. Kennedy
T. Maclean

19. The categories of cost are broken down as follows:
    - DSM is approximately 80% of the business unit budget;
    - BDCS Core is approximately 15%; and
    - Conservation Services is approximately 5% of the 2013 and 2014 O&M budget. No budget for 2015 and 2016 and 2014 is when the contracts end with OPA and LDC's.

20. The DSM budget has a separate regulatory process for application and approval of costs. The recently filed updated 2012 DSM Plan is detailed in EB-2012-0394 for the 2013 and 2014 rate years. The 2014, 2015 and 2016 DSM budget is driven by an assumed inflationary increase of 2% and is subject to future adjustments.

21. BDCS Core O&M costs are net of DSM and Conservation Service activities. The O&M costs support marketing and sales activities, promote, research and introduce new technologies, as well as natural gas transportation activities.

    - Gross salaries and wages and capitalization allocation are for (1) MD&S staff whose activities are related to attaching new customers and (2) NGV staff who support vehicle conversions and equipment installations.

    - Employee Development and Travel Expenses are costs required for training, developing and managing staff to deliver and promote programs for customers.

    - Program Costs are comprised of material and supplies, outside service fees, consulting costs, membership and other miscellaneous costs for MD&S and Business Development.

Witnesses: L. Kennedy
T. Maclean

- Internal Allocation and recoveries are offsetting credits for Conservation Service's overhead recoveries.

22. Conservation Services costs are for the HPNC Program under contract with the OPA and LDC's as described above.

Productivity

23. Over the last several years, BDCS O&M costs have decreased. This is primarily driven by a reduction in FTEs showing a decrease in salary and wages from senior management, supervisory and administrative support staff, through attrition and restructuring to become more cost effective. Reduction in FTEs is also attributed to contracts ending with HPNC and LDC's projects. Also management continues to reevaluate the effectiveness of programs and associated costs.

2014 O&M Budget and Full-Time Equivalents (FTEs)

24. The Business Development and Customer Strategy (BDCS) Department's entire 2014 O&M Budget is $40.3 million for all groups excluding Customer Care. The $40.3 million is comprised of $32.2 million for Demand-Side Management (DSM), $1.9 million for Conservation Services, and $6.2 million for the remainder of Business Development and Customer Strategy ("BDCS Core"). The 2014 Budget for Full-Time Equivalents (FTE's) positions are 128 and submitted in Table 1.

2015 O&M Budget and Full-Time Equivalents (FTEs)

25. The BDCS department's entire 2015 O&M Budget is $39.2 million for all groups excluding Customer Care. The $39.2 million is comprised of $32.8 million for DSM and $6.4 million for Business Development and Customer Strategy ("BDCS Core"). The 2015 Budget for (FTEs) positions are 120 and submitted in Table 1.

Witnesses: L. Kennedy
T. Maclean

2016 O&M Budget and Full-Time Equivalents (FTE's)

26. The BDCS department's entire 2016 O&M Budget is $40.0 million for all groups excluding Customer Care. The $40.0 million is comprised of $33.5 million for DSM and $6.5 million for BDCS Core. The 2016 Budget for FTEs positions is 120 and submitted in Table 1.

Year over Year Comparison

2014 Budget vs 2013 ADR Budget by Expense Type

27. The 2014 O&M Budget for the BDCS department is $40.3 million and the 2013 O&M Budget is $40.8 million. This is a decrease of $0.5 million. The 2014 O&M Budget compared to the 2013 O&M Budget can be found in Table 2.

28. The 2013 O&M Budget of $40.8 million is comprised of $31.6 million for DSM, $6.5 million for BDCS "Core" and $2.7 million for Conservation Services. The 2013 O&M budget can be found in Table 2.

29. The 2014 O&M Budget for BDCS Core is $6.2 million and 2013 O&M Budget for BDCS Core is $6.5 million. Total decrease of $0.3 million. The major variances by expense type are in net salaries and wages and internal allocation and recoveries.

30. The 2014 O&M Budget for net salaries and wages is $3.3 million and the 2013 O&M Budget for net salaries and wages is $3.8 million. This is a net decrease of $0.5 million. The decrease is primarily driven by reduction of 4 FTEs positions in Market Development and Sales.

31. The 2014 O&M Budget for internal allocation and recoveries is minus $0.4 million and the 2013 O&M Budget is minus $0.5 million.

Witnesses: L. Kennedy
T. Maclean

Decrease of $0.1 million is primarily driven by lower overhead recoveries from Conservation Services.

32. The 2014 O&M Budget for DSM is $32.2 million and the 2013 O&M Budget is $31.6 million. This is an increase of $0.6 million. The DSM budget is based on the recently filed application for approval of the updated 2012 DSM Plan for the 2013 and 2014 rate years in EB-2012-0394. Parties agreed that Enbridge's 2012 base budget of $28.1 million would be increased by 10% ($2.8 million) and these additional monies would be applied to low income programs. The 2013 and 2014 budget is escalated by inflation. The increase of $0.6 million is driven by the assumed inflationary rate increase of 2%.

33. The Conservation Services 2014 O&M Budget is $1.9 million. The budget is comprised of O&M and overhead costs for the High Performance New Construction (HPNC) Program with local distribution companies (LDC's) and with Ontario Power Authority (OPA). The 2013 O&M Budget for Conservation Services is $2.7 million and is also comprised of O&M and overhead costs for the High Performance New Construction Program with LDC's and with OPA. The variance is a decrease $0.8 million primarily driven by lower customer incentives, revised budget with OPA and staff reduction due to contracts ending December 2014.

<u>2015 O&M Budget vs 2014 O&M Budget by Expense Type</u>

34. The 2015 O&M Budget for the entire BDCS department is $39.2 million and the 2014 O&M Budget is $40.3 million. This is a net decrease of $1.1 million. A summary can be found in Table 2.

Business Development & Customer Strategy
O&M by Expense Type
Table 2

Line No.	O&M Costs ($000's)	2015 Budget	2014 Budget	2015B vs 2014B
1	Gross Salaries and Wages (net of DSM allocation)	5,036	5,308	(272)
2	Capitalization	(2,040)	(1,994)	(46)
3	Net Salaries and Wages	2,996	3,315	(318)
4	Employee Development and Travel Expenses	720	704	16
5	Program Costs	2,646	2,590	57
6	Internal Allocations and Recoveries	-	(423)	423
7	Total BDCS Core	6,363	6,185	177
8	Demand-Side Management	32,802	32,159	643
9	Conservation Services	-	1,976	(1,976)
10	Total Business Development & Customer Strategy	39,164	40,320	(1,155)
11	Full Time Equivalent (FTE)	120	128	-8

35. The net decrease of $1.1 million is comprised of $1.9 million decrease from Conservation Services program, $0.2 million increase in BDCS Core and $0.6 million increase from DSM.

36. The BDCS Core 2015 O&M Budget is $6.4 million and the 2014 O&M Budget for BDCS Core is $6.2 million. This is a net increase of $0.2 million. This is primarily due to net salary and wages decrease of $0.3 million offset by increase of $0.4 million in internal allocation and recoveries due to lower overhead recoveries.

37. The 2015 O&M Budget for net salary and wages is $3.0 million and 2014 O&M Budget for net salary and wages is $3.3 million. This is a net decrease of $0.3 million. The decrease is primarily driven by transfer of staff to DSM in anticipation

of the 2015 DSM Plan to achieve DSM objectives and program results.

38. There is no 2015 O&M Budget for internal allocation and recoveries. The 2014 O&M Budget for internal allocation and recoveries is minus $0.4 million. The net increase is driven by no contracts with OPA and LDC's.

39. There is no 2015 O&M Budget for Conservation Services. The 2014 O&M Budget is $1.9 million. The net decrease is driven by contracts ending with Ontario Power Authority (OPA) and with local distribution companies (LDC's) in December 2014.

40. 2015 O&M Budget for DSM is $32.8 million and 2014 O&M budget is $32.2 million. The costs increased by $0.6 million driven by assumed inflationary increase of 2%. The DSM budget is based on the recently filed application for approval of the updated 2012 DSM Plan for the 2013 and 2014 rate years in EB-2012-0394. The same inflationary increase of 2% is assumed for 2015.

41. The Business Development and Customer Strategy (BDCS) Department's total FTE's positions for 2015 are 120 and for 2014 are 128. The decrease of 8 positions is in Conservation Services due to contracts ending with LDC's and OPA.

<u>2016 O&M Budget vs 2015 O&M Budget by Expense Type</u>

42. The 2016 O&M Budget is $40.0 million and the 2015 O&M Budget is $39.2 million. Total increase of $0.8 million. A summary can be found in Table 3.

Business Development & Customer Strategy
O&M by Expense Type
Table 3

Line No.	O&M Costs ($000's)	2016 Budget	2015 Budget	2016B vs 2015B
1	Gross Salaries and Wages (net of DSM allocation)	5,153	5,036	117
2	Capitalization	(2,088)	(2,040)	(48)
3	Net Salaries and Wages	3,065	2,996	69
4	Employee Development and Travel Expenses	736	720	16
5	Program Costs	2,705	2,646	59
6	Total BDCS Core	6,506	6,363	144
7	Demand-Side Management	33,458	32,802	656
8	Total Business Development & Customer Strategy	39,964	39,164	800
9	Full Time Equivalent (FTE)	120	120	0

Note:
1) Business Development and Customer Strategy O&M excludes Customer Care

43. The total increase of $0.8 million is comprised of $0.1 million from BDCS Core and $0.7 million for DSM.

44. BDCS Core 2016 O&M Budget is $6.5 million and the 2015 O&M Budget for BDCS Core is $6.4 million. This is a net increase of $0.1 million primarily in net salary and wages and program costs.

45. The 2016 O&M Budget for DSM is $33.5 million and the 2015 O&M Budget is $32.8 million. This is an increase of $0.7 million. The increase is based on inflationary increase of 2%. The DSM budget is based on the recently filed application for approval of the updated 2012 DSM Plan for the 2013 and 2014 rate years in EB-2012-0394. The same inflationary increase of 2% is assumed for 2016.

Witnesses: L. Kennedy
T. Maclean

46. Table 4 shows a summary of the 2013, 2014, 2015 and 2016 O&M Budget for the Direct Purchase group.

Business Development & Customer Strategy
Customer Care
Direct Purchase
Table 4

Line No.	O&M Costs ($000's)	2013 Budget	2014 Budget	2015 Budget	2016 Budget
1	Salaries & Wages	1,969	2,012	2,057	2,104
2	Employee Development, Travel & Other	478	322	342	345
3	Total Direct Purchase	2,447	2,334	2,399	2,449
4	Full Time Equivalent (FTE)	25	25	25	25

47. Salaries and wages represent the majority of the O&M costs. Employee Development, Travel & Other consists of costs for employee training and development; travel; external professional and other services; and memberships.

48. The reduction in Total O&M from 2013 to 2014 is driven by an increase in costs due to wage inflation being more than offset by the Company's efforts to reduce costs overall.

49. The increase in Total O&M from 2014 to 2015 and 2015 to 2016 is predominantly due to wage inflation.

Witnesses: L. Kennedy
T. Maclean

HUMAN RESOURCES DEPARTMENT - O&M BUDGET

Mandate and Responsibilities

1. The Human Resources Department is comprised of two functions – Human Resources and Facilities Services.

2. Human Resources is responsible for ensuring that Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") is able to attract, develop and retain talented people to meet the needs of the business, ensuring operational excellence.

3. The Facilities Services department manages all Enbridge facilities (currently 20 properties, 11 owned and 9 leased, totaling 818,000 square feet) ensuring that appropriate facilities and workspace are available to support and respond to the operational requirements of the Company and provides 24/365 response to all building emergencies. The department is responsible for the planning and utilization of buildings to provide a safe and healthy work environment for all building occupants while optimizing the use and efficiency of all facilities ensuring adherence to building codes and by-laws, fire codes, and environmental regulations.

Services and Activities

4. The Human Resources department consists of various functions as described below. All the functions, with the exception of Business Support, are Centers of Expertise which are supplemented by services purchased through the Service Level Agreement with Enbridge Inc.
    - Business Support, provides services related to recruitment and selection, and the execution of such programs as succession management,

performance management and employee engagement. This group also provides overall organizational support and consultation on human resource matters.

- Total Compensation develops the compensation strategy including base pay, STIP, LTIP, pension and benefits in order to maintain Enbridge's competitive position in the market.
- Organizational Effectiveness develops programs to assist in employee development, leadership effectiveness and performance management.
- Employee Services provides payroll, pension and benefit services to all employees.

5. Facilities Services conducts strategic property planning, acquisition and disposal of properties, lease administration, asset management and internal project management of all reconfiguration, relocation, renovation and construction projects. The daily operation of buildings and grounds entails the maintenance and upgrade of building systems, energy management initiatives, premise security, life safety systems, business continuity planning, mail and delivery and housekeeping services.

6. Table 1 provides a combined summary of O&M expenses for Human Resources and Facilities Services for the 2013 to 2016 fiscal years.

Table 1

Human Resources Budget for 2013, 2014, 2015 and 2016

Line No.	Particulars ($ 000's)	2013 Budget	2014 Budget	2015 Budget	2016 Budget
1	Salaries and Wages	$ 6,123	$ 6,134	$ 6,267	$ 6,407
2	STIP	20,700	21,156	21,628	22,116
3	Benefits Pension & Other Post	25,261	25,756	26,350	26,925
4	Pension & Other Post Retirement Benefits (OPEB)	42,800	37,250	33,760	30,890
5	Outside Services	5,574	6,143	6,291	6,475
6	Rents and Leases	3,813	3,554	3,665	3,701
7	Costs Charged to Affiliates	(558)	(552)	(552)	(552)
8	Other	6,508	6,693	6,791	6,939
9	Total	110,221	106,134	104,200	102,901
10	Full-Time Equivalent ("FTE")	79	77	77	77

7. The 2014 Budget for Human Resources is $106.1 million as illustrated in Table 1.

Witnesses: R. Riccio
S. Trozzi

8. Total FTEs forecast for the 2014 budget is 77. The Human Resources and Facilities Services group consists of Management, Supervisory and Unionized employees who provide services to the rest of the Company. Salaries and Wages for these FTEs is $6.1 million of the total O&M budget.

9. A large component of the 2014 budget is Short Term Incentive pay ("STIP"), with a budget of $21.2 million. The STIP is the variable pay component of compensation for all permanent employees as outlined in Employee Expenses and Workforce Demographics, Exhibit D1, Tab 3, Schedule 2.

10. STIP is a pay-at-risk program in that payment is tied to achievement of previously-established results, and must be re-earned each year, see Employee Expenses and Workforce Demographics, Exhibit D1, Tab 3, Schedule 2.

11. The 2013 to 2016 STIP Budget is outlined below. There are three key factors that are measured for STIP calculation purposes; (1) Enbridge Inc. Company Multiplier is measured by Corporate Return on Equity ("ROE"), (2) Enbridge Multiplier is measured on the business unit scorecard results, (3) Individual Performance (non-unionized employees) is reflected by an employee's overall performance rating assigned by the manager. The Company Performance (ROE or "Company Multiplier") and the Business Unit Performance ("Enbridge Multiplier") targets are outlined below. For budgeting purposes, the Company uses a multiplier of one for each of the three factors. Where the actual multiplier used is greater than one, it means that all or some combination of the performance measures has been exceeded.

Table 2

	2013 Budget $000	2014 Budget $000	2015 Budget $000	2016 Budget $000
Short Term Incentive Program	$20,700	$21,156	$21,628	$22,116
Enbridge Inc. Multiplier	1.00	1.00	1.00	1.00
Enbridge Multiplier	1.00	1.00	1.00	1.00

12. The calculation of the STIP is based on an increase in the salary base of 2.2% from 2013 budget and both the “Enbridge Inc. multiplier” and “Enbridge multiplier” is estimated at 1.00. The STIP component of the total compensation is a critical element in maintaining the Company’s competitive position in the market at the 50th percentile.

13. Benefits are another major component of the 2014 Budget, at $25.8 million. See Employee Expenses and Workforce Demographics at Exhibit D1-3-2 for additional information on benefits.

14. Pension and OPEB costs, as provided by Mercer Canada Limited (“Mercer”), are forecasted at $37.3 million for the 2014 Budget. Mercer’s Reports are in Appendices 1 and 2 of this Exhibit.

    Appendix 1: Updated Estimated 2014 – 2018 Accrual Costs, EGD Pension Plans, 28 March 2013
    Appendix 2: Updated Estimated 2014 – 2018 Accrual Cost, EGD Non-Pension Post Retirement Plans, 1 April 2013

15. Outside Services are budgeted at $6.1 million. This budget includes facilities contractor costs associated with the daily operation of buildings and building utility costs.

16. Rents and Leases for 2014 are budgeted at $3.6 million.

17. Costs Charged to Affiliates include charges to Enbridge Gas New Brunswick and Gazifère for employee records maintenance, benefit, pension and payroll administration. These costs are budgeted at ($0.6) million.

18. Other expenses include consulting fees, employee training and development, materials and supplies, travel, severances and membership fees. The Company anticipated that these expenses will increase by inflation, and therefore have adjusted the budget accordingly. They are budgeted at $6.7 million.

Variance Explanations – 2014 Budget vs. 2013 Budget

Table 3

Human Resources Department
Operating and Maintenance Expense
2014 Budget versus 2013 Budget

Line No.	Particulars ($ 000's)	2014 Budget	2013 Budget	2014 Budget vs. 2013 Budget
1	Salaries and Wages	$ 6,134	$ 6,123	$ 11
2	STIP	21,156	20,700	456
2	Benefits	25,756	25,261	495
3	Pension & OPEB	37,250	42,800	(5,550)
4	Outside Services	6,143	5,574	569
5	Rents and Leases	3,554	3,813	(259)
6	Costs Charged to Affiliates	(552)	(558)	6
7	Other	6,693	6,508	185
8	Total Gross Operating and Maintenance Expense	106,134	110,221	(4,087)
9	FTE	77	79	(2)

19. The 2014 Budget decreases by $4.1 million from the 2013 Budget.

20. The 2014 salaries and wages budget increases by $0.01 million from the 2013 Budget due to salary increases partially offset by not renewing contracts of temporary employees.

21. The STIP budget for 2014 is $0.5 million higher than the 2013 budget. The increase is due to a higher salary base across the Company.

22. Benefits increase by $0.5 million, this represents a 2% increase. The Company expects, however, that cost pressures on benefits will be significantly higher at 6%. The increase is driven by: (1) increase for Canada Pension Plan, Employment Insurance, and Employers Health Tax due to a higher salary base; (2) higher prescription costs, dental fees; (3) the impact of higher employee utilization. Notwithstanding these cost pressures, the Company is committed to manage these costs within a 2.2% increase from 2013 Budget. As previously noted, more details about benefits benefits are outlined in Employee Expenses and Workforce Demographics, Exhibit D1-3-2.

23. Pension and OPEB costs, as provided by Mercer, decrease by $5.6 million from the 2013 Budget due to expected returns on higher pension plan asset balances.

24. Outside Services increase by $0.6 million from the 2013 Budget due to higher contractor costs for planned building moves in 2014.

25. Rents and Leases decrease by $0.3 million from the 2013 Budget due to the deferral of a planned acquisition for additional office space to accommodate employee growth at the head office facility.

26. Costs Charged to Affiliates remain virtually unchanged.

27. Other expenses increase by $0.1 million from 2013 Budget primarily due to severance costs increasing as a result of increasing salary costs.

Variance Explanations – 2015 Budget vs. 2014 Budget

Table 4

Human Resources Department
Operating and Maintenance Expense
2015 Budget versus 2014 Budget

Line No.	Particulars ($ 000's)	2015 Budget	2014 Budget	2015 Budget vs. 2014 Budget
1	Salaries and Wages	$ 6,267	$ 6,134	$ 133
2	STIP	21,628	21,156	472
2	Benefits	26,350	25,756	594
3	Pension and OPEB	33,760	37,250	(3,490)
4	Outside Services	6,291	6,143	148
5	Rents and Leases	3,665	3,554	111
6	Costs Charged to Affiliates	(552)	(552)	0
7	Other	6,791	6,693	98
8	Total Gross Operating and Maintenance Expense	104,200	106,134	(1,934)
9	FTE	77	77	0

28. The 2015 Budget will see an overall decrease of $1.9 million over the 2014 Budget.

29. Salaries and wages increase by $0.1 million due to general wage increases.

30. The STIP budget for 2015 is $0.5 million higher than the 2014 budget due to a higher salary base across the Company.

31. Benefits increased by $0.6 million driven by: (1) an increase for Canada Pension Plan, Employment Insurance, and Employer Health Tax due to a higher salary base; (2) higher prescription costs and, dental fees, and (3) the impact of higher employee utilization. Again, the Company anticipates that actual benefit costs will exceed the budgeted increase.

32. Pension and OPEB costs, as provided by Mercer, decrease by $3.5 million from the 2014 Budget due to expected higher returns on higher pension plan asset balances.

33. Outside Services increase by $0.1 million due to higher facilities contactor costs and increases in utility costs due to inflation.

34. Rents and Leases are $0.1 million higher than in 2014. This is due to a planned acquisition of a new operations depot replacing a previously leased property that no longer meets the current and future special purpose needs of the operations function in the Casselman area of the Company's eastern Ontario region.

35. Other expenses increase by $0.1 million due to inflationary pressures.

Variance Explanations – 2016 Budget vs. 2015 Budget

Table 5

Human Resources Department
Operating and Maintenance Expense
2016 Budget versus 2015 Budget

Line No.	Particulars ($ 000's)	2016 Budget	2015 Budget	2016 Budget vs. 2015 Budget
1	Salaries and Wages	$ 6,407	$ 6,267	$ 140
2	STIP	22,116	21,628	488
2	Benefits	26,925	26,350	575
3	Pension and OPEB	30,890	33,760	(2,870)
4	Outside Services	6,475	6,291	184
5	Rents and Leases	3,701	3,665	36
6	Costs Charged to Affiliates	(552)	(552)	0
7	Other	6,939	6,791	148
8	Total Gross Operating and Maintenance Expense	102,901	104,200	(1,299)
9	FTE	77	77	(0)

36. The 2016 Budget will see an overall decrease of $1.3 million over the 2015 Budget.

37. Salaries and wages increase by $0.1 million due to general wage increases.

Witnesses: R. Riccio
S. Trozzi

38. The STIP budget for 2016 is $0.5 million higher than the 2015 budget due to a higher salary base.

39. Benefits increased by $0.6 million driven by (1) an increase for Canada Pension Plan, Employment Insurance, and Employer Health Tax due to a higher salary base; (2) higher prescription costs and, dental fees, and (3) the impact of higher employee utilization. Again, the Company anticipates that actual Benefits costs will exceed the budgeted increase.

40. Pension and OPEB costs, as provided by Mercer, decrease by $2.9 million from the 2015 Budget due to expected returns on higher pension plan asset balances.

41. Outside Services increase by $0.2 million due to higher facilities contactor costs and increases in utility costs due to inflation.

42. Rents and Leases increase by a marginal amount due to inflationary pressures.

43. Other expenses increase by $0.1 million due to inflationary pressures.

MERCER

TALENT • HEALTH • RETIREMENT • INVESTMENTS

UPDATED ESTIMATED 2014 – 2018 ACCRUAL COSTS

EGD PENSION PLANS

28 MARCH 2013

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations and projections:

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A projection is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in accounting standards and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

Because actual plan experience will differ from the assumptions used in this projection, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a projection or a valuation report.

CONTENTS

1

Introduction

Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the accrual (i.e. pension accounting) costs over 2014 to 2018 for:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates (the "SSERP"),

based on economic conditions at February 28, 2013. Actual accrual costs in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of pension costs from ratepayers.

Note that information contained in this report reflects all assets, liabilities and costs in respect of all employers participating in the EGD RPP, except where specifically noted.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

2

Background Information

Determination of Accrual Costs

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Accrual costs in respect of the EGD RPP are determined annually based on actuarial valuations and extrapolations for financial reporting purposes. The SERP and SSERP are closed supplemental pension arrangements sponsored by Enbridge Gas Distribution Inc. and are relatively small compared to the EGD RPP. Projected costs for the SERP and SSERP have been included here for completeness.

The Company has indicated that only direct charges to the Statement of Profit & Loss ("P&L charges") are applicable for determining costs on the accrual basis. Therefore, all accrual costs in the body of this report only reflect P&L charges. Charges to the Statement of Other Comprehensive Income ("OCI charges") have been included in Appendix B, for information purposes.

Accounting Standards and Methodology

The most recent actuarial valuation of the plans for financial reporting purposes was as at December 31, 2012. These valuations have been extrapolated forward and are the basis for the projections contained herein.

The Company's fiscal year end date is December 31, and the measurement date for plan assets and obligations as described in this report is December 31.

Results contained in this report are in accordance with US GAAP.

All results presented in this report are in Canadian dollars.

For year-end 2012 financial reporting, the Company adopted the Enhanced Mercer Model discount rate methodology. As of December 31, 2012 the Enhanced Mercer Model methodology resulted in a discount rate approximately 40 basis points higher than the rate determined using the Company's previous methodology (the methodology proposed by the Canadian Institute of Actuaries ("CIA") in September 2011). We have based our projections on accounting discount rates determined using the Enhanced Mercer Model methodology going forward.

Additional details on the assumptions and methodology used in these projections are given in Appendix E.

3

Financial Results

Financial Position at December 31, 2012 and Projected Future Financial Positions

We have projected the results of the December 31, 2012 actuarial valuations of the plans for financial reporting purposes forward to each of the years ending 2013 through 2017. The purpose of these projections is to estimate the accrual costs for 2014 through 2018. **The projections are based on the economic environment as at February 28, 2013 and assumptions described in Appendix E. The actual economic environment as at each of the years ending 2013 through 2017 and actual plan experience over this period may differ significantly from these assumptions.**

For simplicity, we have excluded assets and benefit obligations with respect to the DC provision of the EGD RPP in the balance sheets shown below. However, the DC accrual costs of the EGD RPP are included in the P&L charges shown on pages 5 and 6.

Projected Accounting Balance Sheets

The table below details the actual balance sheet position of the plans as at December 31, 2012, as well as the projected position of the plans at each of year-end 2013 through 2017, assuming plan experience unfolds according to the assumptions described in Appendix E.

Balance Sheet Position ($Millions)

	EGD RPP	SERP	SSERP	TOTAL
12.31.2012 (Actual)				
Assets	$756.1	$15.7	$7.7	$779.5
Benefit obligation	$882.5	$15.6	$4.8	$902.9
Excess (deficit)	($126.4)	$0.1	$2.9	($123.4)
12.31.2013 (Projected)				
Assets	$838.4	$16.5	$7.6	$862.5
Benefit obligation	$909.4	$15.3	$4.5	$929.2
Excess (deficit)	($71.0)	$1.2	$3.1	($66.7)
12.31.2014 (Projected)				
Assets	$891.3	$16.3	$7.4	$915.0
Benefit obligation	$936.0	$15.0	$4.3	$955.3
Excess (deficit)	($44.7)	$1.3	$3.1	($40.3)
12.31.2015 (Projected)				
Assets	$940.3	$16.0	$7.2	$963.5
Benefit obligation	$962.8	$14.6	$4.0	$981.4
Excess (deficit)	($22.5)	$1.4	$3.2	($17.9)
12.31.2016 (Projected)				
Assets	$986.1	$15.6	$7.0	$1,008.7
Benefit obligation	$989.6	$14.3	$3.7	$1,007.6
Excess (deficit)	($3.5)	$1.3	$3.3	$1.1
12.31.2017 (Projected)				
Assets	$1,029.3	$15.1	$6.7	$1,051.1
Benefit obligation	$1,016.7	$13.9	$3.4	$1,034.0
Excess (deficit)	$12.6	$1.2	$3.3	$17.1

Summary of Accrual Costs

Based on the projected financial positions above, the resulting US GAAP P&L accrual costs for the plans over 2014 – 2018 are summarized below.

Accrual Costs - US GAAP ($Millions)

	EGD RPP	SERP	SSERP	TOTAL
2014 Projected P&L Charge	$31.5	$0.6	($0.1)	$32.0
2015 Projected P&L Charge	$28.2	$0.5	($0.1)	$28.6
2016 Projected P&L Charge	$25.5	$0.4	($0.1)	$25.8
2017 Projected P&L Charge	$23.0	$0.4	($0.1)	$23.3
2018 Projected P&L Charge	$20.8	$0.3	($0.1)	$21.0

Enbridge Gas Distribution Inc.'s Share of Funding

In addition to Enbridge Gas Distribution Inc., two other smaller employers participate in the EGD RPP. The following tables provide the same results as those on page 5, but are only in respect of Enbridge Gas Distribution Inc.'s share of costs[1].

Accrual Costs - US GAAP ($Millions) - EGDI Only

	EGD RPP	SERP	SSERP	TOTAL
2014 Projected P&L Charge	$29.5	$0.6	($0.1)	$30.0
2015 Projected P&L Charge	$26.2	$0.5	($0.1)	$26.6
2016 Projected P&L Charge	$23.4	$0.4	($0.1)	$23.7
2017 Projected P&L Charge	$21.0	$0.4	($0.1)	$21.3
2018 Projected P&L Charge	$18.8	$0.3	($0.1)	$19.0

[1] Note that Enbridge Gas Distribution Inc. is the only employer participating in the SERP and SSERP.

Important to Note

The purpose of this report is to estimate the accrual costs over 2014 through 2018. However, the actual level of costs in 2014 through 2018 is highly dependent on:

- Financial market returns after February 28, 2013;
- Changes in long-term high-quality corporate bond yields after February 28, 2013;
- Amount of funding contributions paid into the plan;
- Any changes to the Company's discount rate methodology in the future; and,
- Actual plan demographic experience.

These items will cause actual accrual costs over 2014 through 2018 to differ from the estimates provided in this report.

4

Actuarial Opinion

The methods used in the projections of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of US accounting standards (US GAAP).

Management has selected the assumptions used in the projections of plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with US accounting standards (US GAAP). We are not expressing any opinion on these assumptions.

In our opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The calculations have been made in accordance with the requirements of US accounting standards (US GAAP), reflecting application of the Company's accounting policies described in this report.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

Danielle Neville FSA, ACIA	Tyler Brady FSA, FCIA
March 28, 2013 Date	March 28, 2013 Date

APPENDIX A

Sensitivity of Results

The estimated impact on accrual costs of positive and negative "shocks" to the plan's assets and benefit obligations are given in this appendix. These "shocks" are assumed to occur at the end of 2014 in all scenarios.

Amounts in this appendix reflect only Enbridge Gas Distribution Inc.'s share of costs.

Equity markets return +/- 20% more than expected

This scenario assumes that equity markets return 20% more or less than baseline assumptions, resulting in a return over 2014 that is 12.0%[2] higher or lower than our baseline assumption of 6.31% for the EGD RPP and 3.20% for the SERP and SSERP.

Table A.1: Positive Asset Shock in 2014 (+20% equity return)

	Accrual Costs - EGDI Only ($millions)	
	US GAAP P&L CHARGE	***Δ from baseline***
2014	$30.0	-
2015	$10.7	*($15.9)*
2016	$10.7	*($13.0)*
2017	$10.9	*($10.4)*
2018	$11.0	*($8.0)*

Table A.2: Negative Asset Shock in 2014 (-20% equity return)

	Accrual Costs - EGDI Only ($millions)	
	US GAAP P&L CHARGE	***Δ from baseline***
2014	$30.0	-
2015	$42.5	*$15.9*
2016	$37.7	*$14.0*
2017	$33.4	*$12.1*
2018	$29.9	*$10.9*

[2] EGD RPP assets include a 60.0% allocation to growth assets, multiplied by +/- 20% equals return adjustment of +/- 12.0%. SERP and SSERP assets include a 35% allocation to growth assets, so the adjustment for these plans is +/- 7.0%.

Yield curve shift of +/- 1%

This scenario assumes a year-end 2014 parallel shift in the yield curve which benefit obligation discount rates are based on. We have assumed this change would not impact the fixed income portion of the plan's assets. In other words, this sensitivity is intended to represent a pure obligation shock (resulting from any economic or demographic experience different than expected), whereas the previous sensitivity was a pure asset shock.

Table A.3: Positive Obligation Shock in 2014 (+1% shift in yield curve)

	Accrual Costs - EGDI Only ($millions)	
	US GAAP P&L CHARGE	**Δ *from baseline***
2014	$30.0	-
2015	$12.3	*($14.3)*
2016	$12.7	*($11.0)*
2017	$13.4	*($7.9)*
2018	$14.2	*($4.8)*

Table A.4: Negative Obligation Shock in 2014 (-1% shift in yield curve)

	Accrual Costs - EGDI Only ($millions)	
	US GAAP P&L CHARGE	**Δ *from baseline***
2014	$30.0	-
2015	$37.7	*$11.1*
2016	$31.7	*$8.0*
2017	$26.5	*$5.2*
2018	$22.1	*$3.1*

APPENDIX B

Total Accrual Costs

The accrual costs shown on pages 5 and 6, and in Appendix A, are only in respect of direct charges to the P&L statement. Under US GAAP, additional charges (primarily in respect of recognizing actuarial gains and losses) are reflected in the OCI statement. This appendix includes estimates of both direct P&L charges and indirect OCI charges over 2014 through 2018.

Amounts in this appendix reflect only Enbridge Gas Distribution Inc.'s share of costs.

Accrual Costs - US GAAP ($Millions) - EGDI Only

	P&L CHARGE	OCI CHARGE	TOTAL CHARGE
2014 Charge	$30.0	$4.6	$34.6
2015 Charge	$26.6	$4.9	$31.5
2016 Charge	$23.7	$5.1	$28.8
2017 Charge	$21.3	$5.3	$26.6
2018 Charge	$19.0	$5.6	$24.6

APPENDIX C

Required Disclosures

Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The information presented in this report has been prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.
- The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions and accounting policies selected by Management;
- We have projected assets forward using actual asset returns (net of expenses) to February 28, 2013 and our best estimate of asset returns (net of expenses) after February 28, 2013. Projected future cash flows have also been incorporated.
- We have projected benefit obligations forward using the expected cost of benefits accruing over 2013 through 2017, reflecting interest over each period and adjusting year-end 2013 benefit obligations to reflect the economic environment as at February 28, 2013. Benefit obligations in future periods are projected forward with these same February 28, 2013 assumptions and methodology. Projected future cash flows have also been incorporated.
- The starting point for our asset projection was the market value of assets as of December 31, 2012, described in Appendix D.
- Our calculations are based on the assumptions and methodology described in Appendix E. The discount rate assumption reflects market conditions as at February 28, 2013 and the Enhanced Mercer Model discount rate methodology.
- Our calculations are based on extrapolations of valuations performed using membership data as at December 31, 2012. The membership data used in our projections and calculations is summarized in Appendix F.
- Our calculations reflect the provisions of the Plan as at February 28, 2013. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix G.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent February 28, 2013 which, in our opinion, would have a material impact on the results of the projection.

APPENDIX D

Plan Assets

The DB assets of the EGD RPP and the invested assets of the SERP and SSERP are held in trust by CIBC Mellon. SERP and SSERP assets also include the refundable tax account held with CRA. We have relied upon the unaudited fund statements provided by CIBC Mellon as at February 28, 2013.

The starting point for our projections of assets were the market value of each plan's assets as at December 31, 2012.

Investment Policy

The plans' administrator adopted a statement of investment policy and procedures, last revised in 2011. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the plans' investment objectives. A significant component of this investment policy is the asset mix.

The target and actual asset mix for the EGD RPP is provided for information purposes:

	Investment Policy – EGD RPP	
	Target @ 2.28.2013	**Actual @ 12.31.2012**
Canadian equities	21.0%	23.0%
Global equities	17.0%	32.1%
Emerging market equities	6.5%	
Fixed income – universe	30.0%	29.4%
Fixed income – real return	10.0%	7.7%
Infrastructure	9.0%	5.1%
Real estate	6.5%	2.0%
Cash and cash equivalents	0.0%	0.7%
	100%	100%

Because of the mismatch between the EGD RPP assets (which are invested in accordance with the above investment policy) and the liabilities (which tend to behave like long bonds) the financial position of the EGD RPP will fluctuate over time. These fluctuations could be significant and could cause the EGD RPP to become under, or over, funded.

APPENDIX E

Accounting Methods and Assumptions

Accounting Methods

Valuation of Assets

The market value of assets is used to determine pension costs.

For purposes of these estimates, we have projected the market values of EGD RPP, SERP and SSERP DB assets at December 31, 2012 using actual asset returns (net of all expenses) from January 1, 2013 to February 28, 2013, and our best estimates of asset returns (net of all expenses) from March 1, 2013 to December 31, 2013. The annual rates of return over 2013 for the EGD RPP, SERP, and SSERP assumed in our projection are as follows:

2013 Annual Rate of Return Assumptions[3]

	EGD RPP DB ASSETS	SERP ASSETS	SSERP ASSETS
Actual asset return (net of all expenses) from January 1, 2013 to February 28, 2013	3.12%	2.11%	2.71%
Best estimate of asset return (net of all expenses) from March 1, 2013 to December 31, 2013	5.23%	2.66%	2.66%
Asset return assumed over 2013	8.51%	4.83%	5.44%

Asset returns after December 31, 2013 are assumed to be 6.31% per year for the EGD RPP, and 3.20% per year for the SERP and SSERP. These assumptions were provided to us by Management.

Estimated future cash flows, including minimum funding contributions have been incorporated into our projections.

Actual assets over year-end 2013 through 2017 will differ from these estimates.

Valuation of Benefit Obligations and Current Service Cost

For purposes of these estimates, we have continued to use the projected unit credit method for the valuation of benefit obligations and current service cost of the plans. The objective under this method is to expense each participant's benefits under the plans as they would accrue, taking

[3] Note that the SERP and SSERP asset returns shown reflect assets held in the refundable tax account held with CRA which earn no investment return.

into consideration future salary increases and the plans' benefit allocation formula. Thus, the total pension, to which each participant is expected to become entitled at retirement, is broken down into units, each associated with a year of past or future credited service.

The benefit deemed to accrue for an individual during a fiscal year is the excess of the accrued benefit for valuation purposes at the end of the fiscal year over the accrued benefit for valuation purposes at the beginning of the fiscal year. Both accrued benefits are calculated from the same projections to the various anticipated separation dates. An individual's benefit obligation is the present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the service cost is the present value of the benefit deemed to accrue in the fiscal year.

The plan's service cost is the sum of the individual service costs, and the plan's benefit obligation is the sum of the individual benefit obligations for all participants under the plan.

There is no current service cost in respect of the SERP or SSERP.

Accounting Policies

Accounting Standards Transition

The Company adopted US GAAP accounting standards on January 1, 2012. For year-end 2012 the Company's financial reports were in accordance with US GAAP accounting standards.

Measurement Date

The Company's fiscal year end date is December 31, and the measurement date for plan assets and obligations under US GAAP is also December 31.

Attribution

Under US GAAP, obligations are attributed to the period beginning on the employee's date of joining the plan and ending on the earlier of the date of termination, death or retirement.

Amortizations of Prior Service Costs and Gains and Losses

The Company has elected to amortize past service costs resulting from plan amendments to the EGD RPP on a linear basis over the average remaining service period of active members expected to receive benefits under the plan at the time the amendments were made.

Cumulative gains and losses in excess of 10% of the greater of the PBO or market value of plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan (10.3 years for the EGD RPP, 4.9 years for the SERP and 13.9 years for the SSERP as at December 31, 2012).

Accounting Assumptions

The following assumptions, provided to us by Management, were used in valuing the benefit obligations under the plan and the employer's pension cost.

Measurement date	December 31
Discount rate	4.30%
Expected rate of return on invested assets – EGD RPP	6.75%
Expected rate of return on invested assets – SERP/SSERP	3.20%
Inflation	2.25%
Increases in pensionable earnings	3.50%
Increases in the YMPE	2.75%
Increases in maximum pension permitted under the *Income Tax Act*	2.75%
Indexation of pensions in payment	1.24% per year in respect of Contributory service, 1.13% per year in respect of Non-Contributory and Senior Manager service
Mortality	UP-1994 generational mortality table
Disability	No allowance for future disabilities
Withdrawal	See tables of sample rates
Expenses	Implicit in long-term rate of return on assets
Retirement	See table of sample rates
Percentage with spouse	80% married
Age difference	A male is assumed to be 2 years older than his spouse
Headcount	No allowance made for headcount growth

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

A 20% retirement rate is assumed in lieu of the above rate in the year in which a member qualifies for early retirement with an unreduced pension and in each subsequent year until age 65.

Our assumptions are based on the economic environment as of February 28, 2013, the Enhanced Mercer Model discount rate methodology, and input provided by the Company for the December 31, 2012 accounting valuation. Assumptions as at year-end 2013 through 2017 will reflect the economic environment and input from the Company at those times, and may differ from those used in these projections.

APPENDIX F

Membership Data

Analysis of Membership Data at December 31, 2012

For purposes of these estimates, we have based our projections on membership data as at December 31, 2012 for each plan, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix E.

Membership data for the EGD RPP as at December 31, 2012 are summarized below.

	12.31.2012 (EGD RPP)
Active Members Accruing Defined Benefit Service (Non-SMEs)	
Number	1,984
Total base earnings at the valuation date	$153,737,000
Average base earnings at the valuation date	$77,500
Average years of Non-SME DB pensionable service	11.4 years
Average age	44.6 years
Active Members Accruing Defined Benefit Service (SMEs)	
Number	35
Total base earnings at the valuation date	$7,373,000
Average base earnings at the valuation date	$210,700
Average years of SME DB pensionable service	3.6 years
Average age	51.2 years
Suspended Defined Benefit Members Accruing Defined Contribution Service	
Number	63
Total base earnings at the valuation date	$5,605,000
Average base earnings at the valuation date	$89,000
Average years of Non-SME DB pensionable service	6.0 years
Average age	47.5 years
Other Suspended Defined Benefit Members (Non-SMEs)	
Number	18
Total base earnings at the valuation date	$1,941,000
Average base earnings at the valuation date	$107,800
Average years of Non-SME DB pensionable service	4.9 years
Average age	40.7 years
Other Suspended Defined Benefit Members (SMEs)	
Number	20
Total base earnings at the valuation date	$5,812,000
Average base earnings at the valuation date	$290,600
Average years of Non-SME DB pensionable service	6.2 years
Average years of SME DB pensionable service	1.1 years
Average age	49.7 years

	12.31.2012 (EGD RPP)
Active Defined Contribution Members without Defined Benefit Service	
Number	182
Total base earnings at the valuation date	$15,357,000
Average base earnings at the valuation date	$84,400
Average age	42.0 years
Suspended Defined Contribution Members without Defined Benefit Service	
Number	7
Total base earnings at the valuation date	$889,000
Average base earnings at the valuation date	$127,000
Average age	33.6 years
Deferred Pensioners	
Number	199
Total annual pension	$964,400
Average annual pension	$4,800
Average age	47.8 years
Pensioners and Survivors	
Number	1,518
Total annual lifetime pension	$31,670,800
Average annual lifetime pension	$20,900
Total annual temporary pension	$2,053,300
Average annual temporary pension	$6,800
Average age	72.0 years

APPENDIX G

Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the plans in effect on February 28, 2013. The plans have not been amended since December 31, 2012.

EGD RPP - DB Component

The following is a summary of the main provisions of the DB component of the EGD RPP in effect on February 28, 2013. This summary is not intended as a complete description of the EGD RPP.

Background	The EGD RPP became effective January 1, 1971. Benefits are based on a set formula and are entirely paid for by Enbridge. Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service. In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan.
Eligibility for Membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All employees are immediately vested as of July 1, 2011.
Employee Contributions	No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • A member becomes immediately vested and may choose to retire as early as age 55.

Normal Retirement Pension	**Contributory Service:** 2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service; less 100% of the Contributory Canada Pension Plan Entitlement. **Non-Contributory Service:** 1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service; less 50% of the Non-Contributory Canada Pension Plan Entitlement; **SME Credited Service:** 2.0% of Final Three Year Average Earnings multiplied by years of SME credited service.
Final Five Year Average Earnings	Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees.
Final Three Year Average Earnings	Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by 3.
Canada Pension Plan Entitlement	**Contributory Service:** One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years. **Non-Contributory Service:** Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing a dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.

Early Retirement Pension	The following benefits apply if a member retires early with the Company's consent: • If the member has attained age 60, the pension payable is as described above in the Normal Retirement section. • If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions. If a member retires without company consent the benefit is actuarially equivalent to the benefit payable at age 65.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $2,696.67, or such other maximum as may apply from time to time indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the *Income Tax Act* rules.
Indexation of Pensions in Payment	On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership. Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis.

Death Benefits	**Death Before Eligible for Early Retirement** If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service. **Death After Eligibility for Early Retirement** If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service. **Death After Retirement** The death benefit payable is in accordance with the form elected. The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP.
Disability Benefits	Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled.

EGD RPP - DC Component

The following is a summary of the main provisions of the DC component of the EGD RPP in effect on February 28, 2013. This summary is not intended as a complete description of the EGD RPP.

Background	The DC component of the EGD RPP became effective July 1, 2001. Employer contributions are remitted to individual member accounts and are credited with interest. Members receive the balance of their individual employer account upon termination, death or retirement.
Eligibility for Membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All employees are immediately vested as of July 1, 2011.
Employee Contributions	No employee contributions are required or permitted.
Employer Contributions	Employer contributions to the DC component are based on a member's points. • less than 40 points: 4.0% of pensionable earnings[4] • 40 to 60 points: 5.5% of pensionable earnings • greater than 60 points: 7.0% of pensionable earnings
Maximum Contribution	The employer contributions are limited to the amounts under the ITA.
Pensionable Earnings	Base salary plus 50% of actual bonus received.

[4] For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

SERP / SSERP

The following is a summary of the main provisions of the SERP and SSERP in effect on February 28, 2013. This summary is not intended as a complete description of the SERP or SSERP.

Background - SERP	The SERP became effective November 19, 1987. It provides to designated employees benefit amounts that would otherwise be payable under the EGD RPP beyond the ITA maximum pension limit on service accrued prior to January 1, 2000. The SERP is closed to new entrants.
Background - SSERP	The SSERP became effective November 19, 1984. Only members designated by Enbridge Gas Distribution Inc. were able to join the SSERP. The SSERP is closed to new entrants, and the only remaining members are pensioners and survivors.

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TALENT • HEALTH • RETIREMENT • INVESTMENTS

UPDATED ESTIMATED 2014 - 2018 ACCRUAL COSTS

EGD NON-PENSION POST RETIREMENT PLANS

01 APRIL 2013

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations and projections:

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A projection is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in accounting standards and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

Because actual plan experience will differ from the assumptions used in this projection, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a projection or a valuation report.

CONTENTS

1

Introduction

Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the accrual (i.e. accounting) costs over 2014 to 2018 for The Non-Pension Post Retirement Plan for Employees of Enbridge Gas Distribution Inc. (the "OPEB Plan") based on economic conditions at February 28, 2013. Actual accrual costs in respect of these years will differ from the amounts estimated here, and will be based on future economic and demographic experience. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery OPEB costs from ratepayers.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

2

Background Information

Determination of Accrual Costs

The EGD OPEB Plan is a defined benefit ("DB") plan. Accrual costs in respect of the Plan are determined annually based on actuarial valuations and extrapolations for financial reporting purposes.

The Company has indicated that only direct charges to the Statement of Profit & Loss ("P&L charges") are applicable for determining costs on the accrual basis. Therefore, all accrual costs in the body of this report only reflect P&L charges. Charges to the Statement of Other Comprehensive Income ("OCI charges") have been included in Appendix B, for information purposes.

Accounting Standards and Methodology

The most recent actuarial valuation of the OPEB Plan for financial reporting purposes was as at September 1, 2012. This valuation has been extrapolated forward and is the basis for the projections contained herein.

The Company's fiscal year end date is December 31, and the measurement date for plan obligations as described in this report is December 31.

All results presented in this report are in Canadian dollars.

Results contained in this report are in accordance with US GAAP.

For year-end 2012 financial reporting, the Company adopted the Enhanced Mercer Model discount rate methodology. As of December 31, 2012 the Enhanced Mercer Model methodology resulted in a discount rate approximately 40 basis points higher than the rate determined using the Company's previous methodology (the methodology proposed by the Canadian Institute of Actuaries ("CIA") in September 2011). We have based our projections on accounting discount rates determined using the Enhanced Mercer Model methodology going forward.

Additional details on the assumptions and methodology used in these projections are given in Appendix D.

3

Financial Results

Financial Position at December 31, 2012 and Projected Future Financial Positions

We have projected the results of the September 1, 2012 actuarial valuations of the OPEB Plan for financial reporting purposes forward to each of the years ending 2012 through 2017. The purpose of these projections is to estimate the accrual costs for 2014 through 2018. **The projections are based on the economic environment as at February 28, 2013 and assumptions described in Appendix D. The actual economic environment as at each of the years ending 2012 through 2017 and actual plan experience over this period may differ significantly from these assumptions.**

Projected Accounting Balance Sheets

The table below details the estimated balance sheet position of the OPEB Plan as at December 31, 2012, as well as the projected position of the plans at each of year-end 2013 through 2017, assuming plan experience unfolds according to the assumptions described in Appendix D.

Balance Sheet Position ($Millions)

	EGD OPEB
12.31.2012	
Assets	$0
Benefit obligation	$102.2
Excess (deficit)	($102.2)
12.31.2013 (Projected)	
Assets	$0
Benefit obligation	$104.1
Excess (deficit)	($104.1)
12.31.2014 (Projected)	
Assets	$0
Benefit obligation	$105.7
Excess (deficit)	($105.7)
12.31.2015 (Projected)	
Assets	$0
Benefit obligation	$106.9
Excess (deficit)	($106.9)
12.31.2016 (Projected)	
Assets	$0
Benefit obligation	$107.9
Excess (deficit)	($107.9)
12.31.2017 (Projected)	
Assets	$0
Benefit obligation	$108.7
Excess (deficit)	($108.7)

Summary of Accrual Costs

Based on the projected financial positions above, the resulting US GAAP P&L accrual costs for the plans over 2014 - 2018 are summarized below.

Accrual Costs – US GAAP ($Millions)

	EGD OPEB
2014 Projected P&L Charge	$5.9
2015 Projected P&L Charge	$5.8
2016 Projected P&L Charge	$5.8
2017 Projected P&L Charge	$5.8
2018 Projected P&L Charge	$5.7

Important to Note

The purpose of this report is to estimate the accrual costs over 2014 - 2018. However, the actual level of costs in 2014 - 2018 is highly dependent on:

- Changes in long-term high-quality corporate bond yields after February 28, 2013;
- Any changes to the Company's discount rate methodology in the future;
- Future health care claims costs and trends; and,
- Actual plan demographic experience.

These items will cause actual accrual costs over 2014 - 2018 to differ from the estimates provided in this report.

4

Actuarial Opinion

The methods used in the projections of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of US accounting standards (US GAAP).

Management has selected the assumptions used in the projections of plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with US accounting standards (US GAAP). We are not expressing any opinion on these assumptions.

In our opinion, for the purposes of the projections,

- The membership data on which the projections are based are sufficient and reliable;
- The calculations have been made in accordance with the requirements of US accounting standards (US GAAP), reflecting application of the Company's accounting policies described in this report.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

Nicholas H. Gubbay	Stella Yingjie Ma
FCIA, FFA	FCIA, FSA
April 1, 2013	April 1, 2013
Date	Date

APPENDIX A

Sensitivity of Results

The estimated impact on accrual costs of positive and negative "shocks" to the plan's benefit obligations are given in this appendix. These "shocks" are assumed to occur at the start of 2014 in all scenarios.

Yield curve shift of +/- 1%

This scenario assumes a parallel shift at the start of 2014 in the yield curve which benefit obligation discount rates are based on.

Table A.1: Positive Obligation Shock in 2014 (+1% shift in yield curve)

	Accrual Costs – ($millions)	
	US GAAP P&L CHARGE	*Δ from baseline*
2014	$5.7	*($0.2)*
2015	$5.7	*($0.1)*
2016	$5.8	-
2017	$5.8	-
2018	$5.8	*$0.1*

Table A.2: Negative Obligation Shock in 2014 (-1% shift in yield curve)

	Accrual Costs – ($millions)	
	US GAAP P&L CHARGE	*Δ from baseline*
2014	$6.9	*$1.0*
2015	$6.8	*$1.0*
2016	$6.6	*$0.8*
2017	$6.5	*$0.7*
2018	$6.4	*$0.7*

Health Care Cost Trends

It should be noted that future health care cost trends are especially difficult to predict and actual experience is likely to differ from expected. In addition, changes to provincial drug benefit plans have the potential to shift some or most of the cost of seniors' drug claims to employer sponsored retiree benefit plans, thereby dramatically increasing the cost of seniors' drugs claimed under the grandfathered portion of the EGD OPEB Plan.

APPENDIX B

Total Accrual Costs

The accrual costs shown on page 5, and in Appendix A, are only in respect of direct charges to the P&L statement. Under US GAAP, additional charges (primarily in respect of recognizing actuarial gains and losses) are reflected in the OCI statement. This appendix includes estimates of both direct P&L charges and indirect OCI charges over 2014 to 2018.

Accrual Costs – US GAAP ($Millions)

	P&L CHARGE	OCI CHARGE	TOTAL CHARGE
2014 Charge	$5.9	($0.2)	$5.7
2015 Charge	$5.8	($0.2)	$5.6
2016 Charge	$5.8	($0.2)	$5.6
2017 Charge	$5.8	($0.1)	$5.7
2018 Charge	$5.7	($0.1)	$5.6

APPENDIX C

Required Disclosures

Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The information presented in this report has been prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.
- The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions and accounting policies selected by Management;
- We have projected benefit obligations forward using the expected cost of benefits accruing over 2013 through 2017; reflecting interest over each period and adjusting year-end 2012 benefit obligations to reflect the economic environment as at February 28, 2013. Benefit obligations in future periods are projected forward with these same February 28, 2013 assumptions and methodology. Projected future cash flows have also been incorporated.
- Our calculations are based on the assumptions and methodology described in Appendix D. The discount rate assumption reflects market conditions as at February 28, 2013 and the Enhanced Mercer Model discount rate methodology
- Our calculations are based on extrapolations of valuations performed using membership data as at September 1, 2012. The membership data used in our projections and calculations is summarized in Appendix E.
- Our calculations reflect the provisions of the Plan as at December 31, 2012. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix F.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent December 31, 2012.which, in our opinion, would have a material impact on the results of the projection.

APPENDIX D

Accounting Methods and Assumptions

Accounting Methods

Funding Policy

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

Valuation of Benefit Obligations and Current Service Cost

For purposes of these estimates, we have continued to use the projected unit credit method for the valuation of benefit obligations and current service cost of the plan. The objective under this method is to expense each participant's benefits under the plan as they would accrue; taking into consideration projection of benefit costs to and during retirement. Thus, the total benefit, to which each participant is expected to become entitled at retirement, is broken down into units, each associated with a year of past or future service.

The benefit deemed to accrue for an individual during a fiscal year is the excess of the accrued benefit for valuation purposes at the end of the fiscal year over the accrued benefit for valuation purposes at the beginning of the fiscal year. Both accrued benefits are calculated from the same projections to the various anticipated separation dates. An individual's benefit obligation is the present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the service cost is the present value of the benefit deemed to accrue in the fiscal year.

The plan's service cost is the sum of the individual service costs, and the plan's benefit obligation is the sum of the individual benefit obligations for all participants under the plan.

Accounting Policies

Accounting Standards Transition

The Company adopted US GAAP accounting standards on January 1, 2012. For year-end 2012 the Company's financial reports were in accordance with US GAAP accounting standards.

Measurement Date

The Company's fiscal year end date is December 31, and the measurement date for plan obligations under US GAAP is also December 31.

Attribution

Under US GAAP, obligations are attributed to the period beginning on the employee's date of joining the plan and ending on the date of "full eligibility", determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement.

Amortizations of Prior Service Costs and Gains and Losses

The Company has elected to amortize past service costs resulting from plan amendments to the EGD OPEB Plan on a linear basis over the average remaining service period of active members expected to receive benefits under the plan at the time the amendments were made.

Cumulative gains and losses in excess of 10% of the accrued benefit obligation are amortized over the average remaining service period of active members expected to receive benefits under the plan (13.2 years at December 31, 2012).

Accounting Assumptions

The following assumptions, provided to us by Management, were used in valuing the benefit obligations under the plan and the Company's benefit cost.

Measurement date	31 December	
Discount rate	4.30%	
Salary increases	3.50% per annum	
Medical cost trend rates	Hospital	4.50% per annum
	Prescription drugs	8.644% per annum in 2012 grading down to 4.50% per annum in and after 2029. The trend rates are reduced by 0.25% per year after age 65 for Ontario members to reflect the inclusion of the Ontario Drug Benefit costs
	Other medical	4.50% per annum
	Vision care	4.50% per annum, with an effective 0% per annum net trend rate due to the low fixed dollar limit that exists for the benefit
Provincial health trend rate (non-grandfathered)		0.00% per annum
Retiree HSA trend rate		0.00% per annum
Dental cost trend rate		4.50% per annum
Mortality	Uninsured Pensioners' (UP) Table for 1994 with generational mortality improvements	
Withdrawal	Rates at sample ages are shown below:	

Age	Male	Female
25	5.0%	13.0%
35	4.6%	8.5%
45	2.5%	3.9%
55	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

Disability incidence	No explicit allowance has been made for disability prior to retirement.
Headcount	No allowance made for headcount growth

Retirement rates

If 30 years of continuous service is not reached between ages 55 and 59 inclusive, then the table rates apply, otherwise 20% of the members will retire at the first age at which 30 years of continuous service and age 55 are reached. At all other ages, rates follow the table below.

Age	Rate
55 – 56	5.0%
57 – 58	7.5%
59	10.0%
60 – 64	20.0%
65	100.0%

Marital status

For active members, 80% are assumed to be married at retirement with males assumed to be 2 years older than their female spouses.
For current retirees, actual marital status and spousal age is assumed.

2012 Age 65 per capita claims costs excluding administration and taxes

Hospital	$77
Prescription drugs	$1,162
Other medical	$176
Vision care	$17
Dental care	$656
Total	$2,088

The current per capita medical and dental costs were based on actual claims experience from 01 July 2010 to 30 June 2012 and adjusted to the midpoint of the valuation year.
Drug costs are shown before the impact of any provincial drug plan.

Provincial Health Premiums

The company pays 50% of the cost of provincial health premiums (shown below) for non-grandfathered retirees in British Columbia. We have incorporated the cost of these premiums in our valuation.

Monthly premiums Single $54 Family $96.
The Company cost is frozen at the above (2004) levels.

Increases in utilization by age

	Cost at Age				
Attained Age	Hospital	Drug	Other Medical	Dental	Vision
55	45%	75%	106%	106%	106%
60	64%	88%	103%	104%	103%
65	100%	100%	100%	100%	100%
70	161%	109%	102%	95%	97%
75	253%	113%	110%	90%	95%
80	388%	114%	121%	83%	92%

Prescription drug offset assumption at age 65 and after	The following cost-offsets were assumed to reflect the impact of provincial drug plans: Québec: 50% Ontario 65% Alberta: 55% Prince Edward Island 35% All other provinces: 0%
Administrative expenses as a percentage of paid claims	Medical: 5.40% plus 2.28% for stop loss charge plus applicable taxes Dental: 5.23% plus applicable taxes Retiree HSA: 5.40% plus applicable taxes Life insurance: 2.50% plus applicable taxes
Taxes	Premium Tax Quebec – 2.55% Other – 2.00% Retail Sales Tax Quebec – 9.00% Ontario – 8.00%
Participation	100% of members are assumed to participate in the retiree health plan.

Our assumptions are based on the economic environment as of February 28, 2013 and input provided by the Company for the December 31, 2012 accounting valuation. Actual assumptions as at year-end 2013 – 2017 will reflect the economic environment and input from the Company at those times, and may differ from those used in these projections.

APPENDIX E

Membership Data

Analysis of Membership Data at September 1, 2012

For purposes of these estimates, we have based our projections on membership data as at September 1, 2012, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix D.

Membership data for the EGD OPEB Plan, including affiliates, as at September 1, 2012 are summarized below.

Active Membership Data

	September 1, 2012			
	Number	**Average Age**	**Average Service**	**Average Salary**
Grandfathered Plan				
Non Union	276	56.9	30.6	$96,086
Union	247	56.8	28.9	$64,943
Part Time	4	64.3	19.5	$49,520
Non-Grandfathered Plan	1,722	40.9	8.3	$76,749
Total	2,249	44.6	13.3	$77,777

Inactive Membership Data

	September 1, 2012		
	Less than age 65	Greater than age 65	Total
Grandfathered Plan			
Number of Retirees	250	924	1,174
Average age of Retirees	61.0	74.9	72.0
Average Life Benefit	$118,033	$5,000	$28,766
Number of Spouses of Retirees	287	624	911
Average age of Spouses	59.1	73.8	69.2
Number of Surviving Spouses	22	182	204
Average Age of Surviving Spouses	56.6	78.9	76.5
Non-Grandfathered Plan			
Number of Retirees			35
Average age of Retirees			61.8
Average Life Benefit			$10,000
Number of Spouses of Retirees			28
Average age of Spouses			61.2
Number of Surviving Spouses			3
Average Age of Surviving Spouses			67.0

APPENDIX F

Summary of Plan Provisions

For purposes of these projections, we have reflected the provisions of the EGD OPEB Plan in effect on December 31, 2012.

The following is a summary of what we understand to be the most relevant plan provisions for purposes of this report. This broadly reflects the benefits communicated to members via membership booklets, announcements and correspondence outlining special terms where applicable. This summary should not be used for purposes of determining individual plan benefits.

Grandfathered Plan Summary (Traditional Plan)

Eligibility

Employees who are eligible to retire under the terms of the pension plan (at age 55) are eligible for post-retirement benefits. Current retirees, surviving spouses, and employees with 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible to elect the traditional plan or the RHSA.

Spouses and dependants of retirees are eligible for health and dental coverage as well. Dental coverage ceases when the retiree reaches age 65.

On the retiree's death, health and dental coverage continues for the spouse and dependents. Dental coverage ceases when the surviving spouse reaches age 65, and there is no continuation of dental coverage if the surviving spouse is over age 65 when the retiree dies.

Cost Sharing

All costs for retiree benefits are employer paid.

Life Insurance

Group	Pre Age 65 coverage	Post Age 65 coverage
Non Union	2 x annual earnings at retirement	$5,000
Union	$40,000	$5,000
Part-Time	$15,000	$5,000

Medical and Dental Benefits

Hospital Benefits

Benefits cover 100% of semi-private room and board charges in excess of charges for ward accommodation and for ward-level user fees, where applicable. Hospital charges related to chronic case services are limited to a lifetime maximum of $10,000 per covered person.

Major Medical Benefits

Reimbursement Percentages

- 100% for paramedical practitioners and vision care expenses.
- 90% of first $1,000 of family's eligible expenses per calendar year and 100% of remaining eligible expenses.

Deductible

- None.

Maximum

- $50,000 per person in any three consecutive calendar years.

Eligible Expenses

- Prescription drugs.
- Ambulance services.
- Medical supplies and services (e.g. artificial limbs, orthopaedic shoes).
- Professional services.
- Services of a registered nurse, subject to a lifetime maximum of $5,000.
- Vision care ($100 per person for frames/lenses, $200 for contacts per person every 24 consecutive months).
- Hospital charges for emergency treatment outside Canada.

Provincial Benefits- Ontario Bill 26

Seniors age 65 and over in Ontario with sufficiently high income are required to pay the first $100 of annual drug costs followed by a $6.11 dispensing fee per prescription. The Plan reimburses retirees for these amounts.

Dental Benefits

Reimbursement Percentages

- 100% of basic expenses.

- 50% of major restorative expenses.
- 50% of orthodontic expenses.

Deductible

- None.

Fee Guide

Current Provincial Dental Association Fee Guide.

Dental Maximums

- $2,000 per person per calendar year for basic and major restorative expenses combined.
- $1,000 per person lifetime for orthodontic expenses.

Non-Grandfathered Plan Summary

Eligibility

Current retirees, surviving spouses, and employees that did not qualify by having 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible for the RHSA plan if the employee has at least five years of employment when they retire.

On the retiree's death, the RHSA continues for dependants. Provincial health premiums also continue to be paid (50%).

Cost Sharing

With the exception of provincial health premiums, all costs for retiree benefits are employer paid.

Life Insurance

Life coverage will be $10,000.

Health Spending Account

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

British Columbia Health Premiums

The Company will pay for British Columbia health premiums at 50% of the 2004 rates.

MERCER

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PIPELINE INTEGRITY & ENGINEERING – O&M BUDGET

1. This exhibit outlines the Company's Pipeline Integrity & Engineering ("PI&E") department's O&M budget for the 2014, 2015 and 2016 fiscal years.

Mandate and Responsibilities

2. Industry events such as the natural gas explosion in San Bruno, California (2010) and Enbridge's oil spill in Marshall, Michigan (2010), and the recent responses and expectations from regulatory bodies, as well as the Technical Standards and Safety Authority Code ("TSSA") Adoption Document FS-196-12, which came into effect November 2012, have caused the Company to reexamine and enhance its work practices to further prevent incidents, and improve environmental, worker and public safety. This has led to Enbridge's growing focus upon efforts to reduce operational risks, with a goal of reducing (and ideally eliminating) incidents and injuries of workers and the public.

3. Enbridge's PI&E department is accountable and responsible for the design and assessment of condition monitoring of the distribution system, identifying plans required to add customers and load, and remediate risks, and for establishing construction, operations and maintenance standards which meet or exceed technical and regulatory requirements.

Department Structure

4. The PI&E department is organized into the following four groups: i) Integrity, ii) Engineering, iii) Distribution Asset Management, and iv) Quality and Training. The responsibilities of each group are discussed in turn below.

Witnesses: J. Briggs
A. Creery
L. Lawler

5. *Integrity*: This group is accountable for the condition-monitoring and mitigation of pipelines and other assets within the distribution system. The sub-groups and their responsibilities are as follows: a) Damage Prevention – administers the Company's damage prevention programs including provision of locates, safe excavation awareness programs and sewer safety inspections. Also, this group has been heavily involved with the development of regulations for Bill 8, the *Ontario Underground Infrastructure Notification System Act* which was passed into law in 2012; b) Leak Management – administers the Company's leak survey programs, and identifies and prioritizes leaks for repair; c) Corrosion Management – administers corrosion prevention programs, which involves methods to prevent, monitor and mitigate corrosion on the distribution system; d) Transmission Integrity – administers the Company's in-line inspection and assessment program for higher stress pipelines (i.e. pipelines operating at or over 20% of their Specific Minimum Yield Strength (SMYS)); e) Distribution Integrity – evaluates the integrity of the remainder of the Company's assets (i.e. pipelines operating below 20% SMYS) through damage and failure analysis and conducting studies on assets; f) Asset Integrity Strategy and Risk Analysis, establishes risk evaluation methodologies and conducts risk analysis on aspects of the system, ensures data integrity and produces the System Integrity and Reliability section of the 10 year iterative Asset Plan.

6. *Engineering*: This group is accountable for ensuring technical compliance with applicable regulations, codes and standards, and participates in industry associations and committees to keep up-to-date on requirements, and to maintain relationships with industry stakeholders and regulators. The subgroups and their responsibilities are as follows: a) Engineering Construction and Maintenance – establishes and maintains policies, procedures and standards for the design,

construction, operation and maintenance of the distribution system; b) Measurement and Regulation – designs stations for measurement and regulation of natural gas in the system; c) Process Safety – ensures the elements of process safety management, a comprehensive framework to assess and manage operational risks, are established and managed in the Company; d) Distribution Technology - participates in research consortiums for developing new technologies for preventing and detecting threats (e.g. damages) on the system. Also, this group works with Operations and Integrity to understand issues and find technology solutions; e) Engineering Material and Evaluation Centre - identifies and approves the use of materials, products and tools in the gas distribution system. It also investigates material faults, and assists in quality assurance evaluations and incident investigations.

7. *Distribution Asset Management*: This group is accountable for ensuring the overall design of the distribution system is capable of meeting the Company's gas delivery requirements. This involves consideration of load growth, system integrity demand requirements, and compliance with municipal and regulatory requirements. The subgroups and their responsibilities are as follows: a) Records Administration – checks and maintains all asset records for accuracy and integrity; b) System Analysis and Design – conducts load modeling to identify reinforcement requirements and determines impacts of project work on system capacity and delivery capabilities, and provides alternatives; c) Area Planning and Design - ensures that the design and drafting components of construction and maintenance plans for distribution facilities are undertaken in a timely and cost effective manner; d) Asset Systems – maintains Geographical Information System (GIS) for asset information to ensure accessibility and accuracy of information; e) Land Services – oversees acquisition and disposal of real estate assets and municipal property tax obligations; f) Asset Plan – produces the annual iterative 10-year Asset Plan.

Witnesses: J. Briggs
A. Creery
L. Lawler

8. *Quality and Training*: This group is accountable for quality assurance programs; training workers to perform such work; ensuring external parties performing work are adequately insured; and ensuring measurement requirements are met. The subgroups and their responsibilities are as follows: a) Quality Assurance and Incident Investigations – oversees quality assurance programs, and conduct incident investigations. The group follows-up on findings to ensure they are closed out, for continuous improvement; b) Technical Training – develops and delivers classroom and practical hands-on training on critical tools, equipment and procedures. It also delivers TSSA accredited programs, and other industry specific technical programs to Enbridge employees and contractors (e.g. Gas Performance Inspector school). To help ensure a competent, skilled and safe workforce, the group also provides tools and training related to competency management programs; c) System Measurement – manages programs involving accreditation of meters for customer installations and meter exchanges, which are requirements overseen by Measurement Canada; d) Risk and Claims – monitors and manages the sufficiency of insurance coverage of contractors performing work, and investigates and settles claims made against the company.

<u>2013 to 2016 O&M Budget</u>

9. Table 1 below summarizes PI&E's O&M budget for 2013 through 2016. The budget is a consolidation of the requirements of the four individual groups which make up the PI&E department.

TABLE 1
Enbridge Gas Distribution Inc.
Operation and Maintenance by Cost Type
Pipeline Integrity & Engineering 2013 to 2016 Budget

Line No.	Particulars (000's)	Budget 2013	Budget 2014	Budget 2015	Budget 2016
1	Gross Salaries and Wages	$ 32,267	$ 32,977	$ 33,711	$ 34,473
2	Capitalization of Salaries and Wages	(20,179)	(20,623)	(21,082)	(21,558)
3	Total Labour	$ 12,089	$ 12,354	$ 12,629	$ 12,915
4	Employee Training and Development	296	304	306	313
5	Materials and Supplies	1,299	1,051	1,066	1,097
6	Outside Services	22,881	23,215	23,890	24,191
7	Consulting	357	435	469	510
8	Repairs and Maintenance	103	104	106	109
9	Fleet	701	710	735	764
10	Rents and Leases	1,436	1,711	1,662	1,932
11	Travel and Other Business Expenses	601	615	632	649
12	Memberships	77	80	81	83
13	Claims, Damages and Legal Fees	863	940	963	974
14	Internal Allocations and Recoveries	(2,538)	(2,514)	(2,665)	(2,761)
15	Total	$ 38,164	$ 39,004	$ 39,874	$ 40,775
	FTEs	430	430	430	430

10. Of the total budget each year, approximately 63% is for Integrity; 9% is for Engineering; 7% is for Distribution Asset Management; and 21% is for Quality and Training.

11. Of the total budget each year, approximately $12.0 million or 32% accounts for *Salaries and Wages*; 61% accounts for *Consulting*, *Outside Services* (i.e. contractor costs for locates and integrity inspections), and *Rents and Leases* (i.e. right-of-ways and easements); and 7% accounts for *Materials*, *Fleet*, and *Other Expenses*.

Witnesses: J. Briggs
A. Creery
L. Lawler

Cost Drivers

12. With the Company's heightened focus on reducing operational risk and associated incidents and injuries, the significant cost drivers for PI&E in 2014 to 2016, in addition to inflationary pressures on salaries and wages, are: i) increases in locate volumes, ii) new and expanded damage prevention programs, iii) new and expanded integrity inspections and assessments on higher stress pipelines, iv) expanded leak survey, and iv) technical training.

13. Forecast spending within the Integrity group (which accounts for approximately 63% of the overall PI&E budget), includes the following:

    a. Activities by the Damage Prevention sub- group accounts for approximately $14.5 million or 37.4% of the overall budget each year. Of this amount, the /u
    delivery of locates to third parties accounts for approximately $13.05 million. /u
    The remaining budget is for programs to reduce third party damages, and Company inspection and oversight of third party locators, high risk excavations, sewer safety programs, and aerial patrols.

    b. Activities by the Transmission and Distribution Integrity sub-groups account for approximately $5.3 million or 14.1% of the overall budget each year. These dollars will be used to conduct integrity assessments, primarily in-line inspections, with state of the art intelligent tools which find crack, metal loss, and mechanical damages on Enbridge's higher stress pipelines.

    c. Activities by the Corrosion and Leak Management sub-groups account for approximately $4.5 million or 11.8% of the overall budget each year. Corrosion monitoring and mitigation will continue. In addition to regular and

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A. Creery
L. Lawler

required leak surveys, increased surveys focused on assets and areas of higher risk are planned over the 2014 to 2016 period.

14. Forecast spending within the Quality and Training group (which accounts for approximately 21% of the overall PI&E budget), includes the following:

    a. Activities by the Technical Training group account for approximately $3.8 million or 10% of the overall budget each year. Enhancements to training programs and delivery will continue through use of the new Technology and Operations Centre.

    b. Additionally, System Measurement accounts for approximately $2.4 million or 6%, Risk and Claims accounts for $1.3 million or 3.4%, Quality Assurance and Incident Investigation accounts for approximately $0.38 million or 1%;

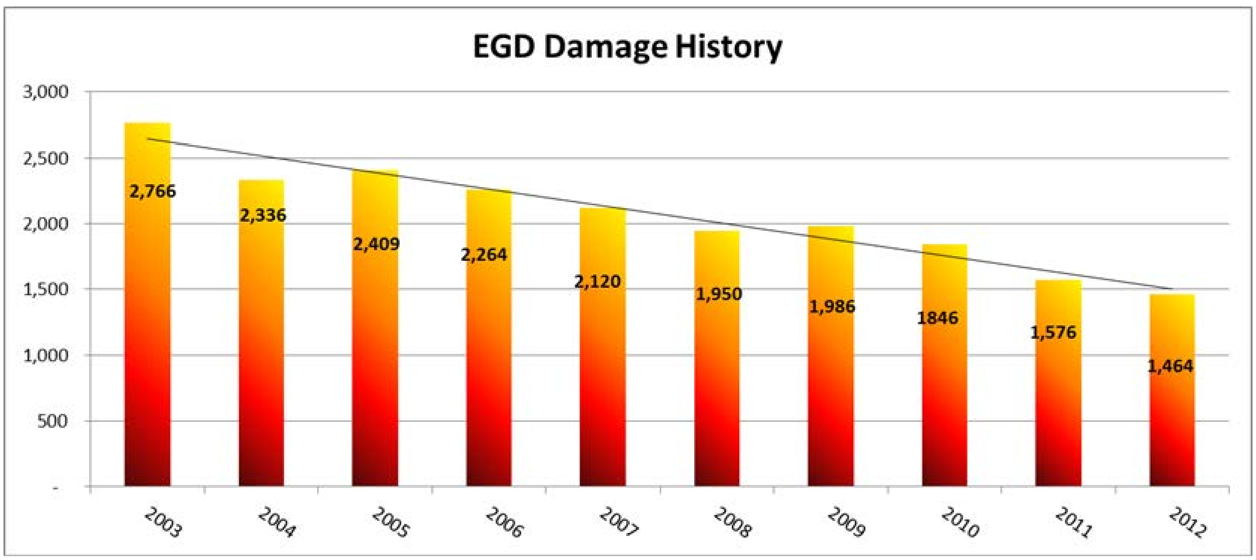
15. The remainder of the budget is for activities by: Distribution Asset Management which accounts for approximately $2.8 million or 7.3%; and Engineering which accounts for approximately $3.4 million or 9%.

16. While many of the responsibilities that must be met by the PI&E Department are not new (such as engineering, construction and maintenance standards, damage prevention, metering, technical training and leak management), the requirements in many areas are increasing.

17. In order to emphasize the increased requirements that the PI&E Department must accommodate, the following sections detail some of the emerging and growing cost drivers that the Department expects to be facing in the 2014 to 2016 term.

18. The Company's largest operational threat is third party damage to the natural gas plant. Preventing damages improves worker and public safety, as well as the integrity of distribution assets. A key prevention measure is to provide locates related to underground plant before excavations are done. The Company has been successful in reducing normalized damages per thousand locate requests as well as absolute damages, as illustrated in Figure 1 below. Forecasted damages for 2013 to 2016 are not shown because such forecasts for total damages in a given year are made during that year based on the actual results. Associated costs will be accommodated within the PI&E O+M Budget.

Figure 1



19. To reduce damages further, Enbridge played a leading role in the development and passage of Bill 8, the *Ontario Underground Infrastructure Notification System Act*. This Act, which was passed in June 2012, requires owners of underground utilities to become members of Ontario One Call (all underground utility owners must become members by June 2013, with the exception of municipalities who must

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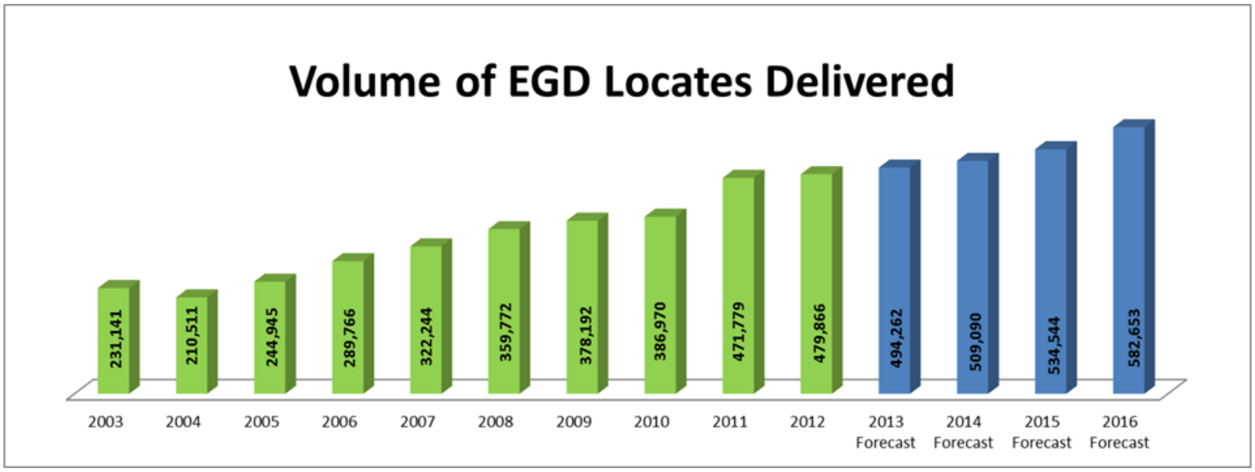
become members by June 2014). Ontario is the first province to implement this system in Canada. This mandatory system exists in all 50 U.S. states, where damages rates are significantly lower than in Ontario. The Act includes requirements such as:

- Excavators must call for locates, and members must provide locates within five (5) business days; and
- Ontario One Call must continue to raise public awareness of Ontario One Call and safe digging practices.

20. The Company expects increases in locate requests, and thus costs, as awareness and appreciation of the system increases and regulations, which are expected to be in place in 2013, are enforced. Figure 2 below illustrates the increase in locates requests over time. Currently, approximately 40% of the Company's damages are from excavations where no locate request was made.

Figure 2



21. Additionally to reduce risk and damages, Enbridge has implemented a High Risk Excavation Program. This program identifies high risk excavations based on excavator damage history; the type of excavation equipment to be used; excavation depth and methodology; the natural gas assets in the vicinity of the excavation; and the potential consequences of a damage. Company Inspectors can then proactively educate excavators on safe digging practices before the excavation begins. The program has resulted in a reduction in risk and damages, and resources are committed to this program to further enhance and promote safe excavation practices in the vicinity of buried natural gas plant.

22. The condition of underground pipelines is proactively determined through the Company's in-line inspection ("ILI") and assessment program for higher stress pipelines. This program identifies cracks, mechanical damage and metal loss, from, for instance, corrosion. Pipelines that have been inspected are re-inspected on a 7-year cycle. ILIs and assessments identify anomalies or features, which are excavated and mitigated in accordance with Company policy, which has been developed based on codes, standards, regulations and industry best practices.

23. Over time, ILI technology has evolved and become more sophisticated. Enbridge intends to invest in and use newer technology as it becomes available, resulting in a better understanding of pipeline condition, which will in turn, improve public safety and reduce risk.

24. To better detect leaks, the Company is moving from a frequency-based leak survey approach (i.e. survey assets on a five-year cycle) to a risk-based approach. This means the Company will investigate potential areas and assets more prone to leaks and will prioritize surveys accordingly. Such investigations have and will continue to

identify areas and assets where leaks are likely to occur. As a result of these efforts, the Company anticipates that survey frequencies will be modified based on assets conditions and risk, and that overall there is a need to increase leak survey frequency on assets approaching the end of their useful life (with relatively high leak frequencies).

25. These cost drivers described above will be managed within the PI&E O&M Budget. This will be a challenge, taking into account that the budget is only increasing by a level close to inflation, and given that there is no forecast increase in the number of FTEs available to undertake the anticipated increasing volume of work. Even if it is subsequently decided that a modest number of FTEs should be added, the associated costs will still have be managed within the same cost envelope. In order to manage within this cost envelope, productivity initiatives will be undertaken by the PI&E Department. These productivity measures are discussed below.

PI&E Department O&M Year-Over-Year Budget Variances

26. In 2014 the budget increases by approximately $0.84 million or approximately 2.2% over 2013 (see Table 2 below). The increase accounts for inflation.

Table 2
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2014 to 2013 Budget

Line No.	Particulars (000's)	2014 Budget	2013 Budget	2014 vs 2013
1	Salaries and Wages	$ 32,977	$ 32,267	$ 710
2	Labour Capitalization	(20,623)	(20,179)	(444)
3	Net Salaries and Wages	$ 12,354	$ 12,089	$ 265
4	Employee Training and Development	304	296	8
5	Materials & Supplies	1,051	1,299	(248)
6	Outside Services	23,215	22,881	334
7	Consulting	435	357	78
8	Repairs and Maintenance	104	103	2
9	Fleet	710	701	9
10	Rents & Leases	1,711	1,436	275
11	Travel and Other Business Expenses	615	601	14
12	Memberships	80	77	3
13	Claims, Damages, and Legal Fees	940	863	77
14	Internal Allocations and Recoveries	(2,514)	(2,538)	24
15	Total	$ 39,004	$ 38,164	$ 840
	FTEs	430	430	-

27. In 2015 the budget increases by approximately $0.87 million or approximately 2.2% over 2014 (see Table 3 below). The increase accounts for inflation.

Witnesses: J. Briggs
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Table 3
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2015 to 2014 Budget

Line No.	Particulars (000's)	2015 Budget	2014 Budget	2015 vs 2014
1	Salaries and Wages	$ 33,711	$ 32,977	$ 734
2	Labour Capitalization	(21,082)	(20,623)	(459)
3	Net Salaries and Wages	$ 12,629	$ 12,354	$ 275
4	Employee Training and Development	306	304	2
5	Materials & Supplies	1,066	1,051	15
6	Outside Services	23,890	23,215	675
7	Consulting	469	435	34
8	Repairs and Maintenance	106	104	2
9	Fleet	735	710	25
10	Rents & Leases	1,662	1,711	(49)
11	Travel and Other Business Expenses	632	615	17
12	Memberships	81	80	2
13	Claims, Damages, and Legal Fees	963	940	23
14	Internal Allocations and Recoveries	(2,665)	(2,514)	(150)
15	Total	$ 39,874	$ 39,004	$ 870
	FTEs	430	430	-

28. In 2016 the budget increases by approximately $0.9 million or approximately 2.3% over 2015 (see Table 4 below). The increase accounts for inflation.

Witnesses: J. Briggs
A. Creery
L. Lawler

Table 4
Enbridge Gas Distribution
Operation & Maintenance by Cost Type
Pipeline Integrity & Engineering 2016 to 2015 Budget

Line No.	Particulars (000's)	2016 Budget	2015 Budget	2016 vs 2015
1	Salaries and Wages	$ 34,473	$ 33,711	$ 762
2	Labour Capitalization	(21,558)	(21,082)	(476)
3	Net Salaries and Wages	$ 12,915	$ 12,629	$ 286
4	Employee Training and Development	313	306	7
5	Materials & Supplies	1,097	1,066	30
6	Outside Services	24,191	23,890	301
7	Consulting	510	469	42
8	Repairs and Maintenance	109	106	3
9	Fleet	764	735	29
10	Rents & Leases	1,932	1,662	270
11	Travel and Other Business Expenses	649	632	17
12	Memberships	83	81	2
13	Claims, Damages, and Legal Fees	974	963	11
14	Internal Allocations and Recoveries	(2,761)	(2,665)	(97)
15	Total	$ 40,775	$ 39,874	$ 900
	FTEs	430	430	-

Productivity

29. The increased focus on enhancing safety, through the many new requirements and activities outlined above, will place significant pressures on the PI&E Department. There will be particular challenges arising from the fact that FTE levels have been frozen for budgeting purposes (such that any FTE additions that subsequently materialize must be funded by savings in other areas), and budgets will only increase by a level of around inflation. Taking this into account, conducting the required incremental work can only be accomplished within the budget specified by

improving productivity in ways which do not sacrifice safety and compliance. While the PI&E Department has not conclusively identified all the ways that it will do this, the following are some examples of areas that are being targeted.

30. Additional costs from increased locate volumes are expected to be offset by savings due to fewer damages, and improved efficiencies from facility owners providing locates within five days. Some of these cost savings will manifest in other areas of Enbridge, such as Operations and Legal, and will be offset with reduction in associated cost recoveries (billing for damages).

31. Increases in leak survey will result in increased costs for the Integrity group, as well as in Operations emergency response and capital replacement requirements. The Company is investigating new technologies for more efficient surveying, to potentially offset some of these costs.

32. Measurement Canada's introduction of regulation SS06, combined with changes in technology and volume purchasing power, caused the Quality & Training group to review practices of repairing residential diaphragm meters. As of March 2013, the repair of 200 and 400 series diaphragm meters have been discontinued; new meters will be purchased thereby eliminating repair costs.

33. The Company also intends to explore cost recovery opportunities associated with the provision of training and/or use of the new Technology and Operations Centre within the industry.

Witnesses: J. Briggs
A. Creery
L. Lawler

O&M – REGULATORY AND PUBLIC & GOVERNMENT AFFAIRS

1. The Regulatory and Public & Government Affairs ("RPGA") business unit encompasses two departments, Regulatory Affairs and Public & Government Affairs.

Regulatory Affairs Responsibilities

2. The Company's regulatory activities require participation in proceedings before the Ontario Energy Board ("the Board") for their review and decision with respect to Enbridge specific and generic issues, interventions in proceedings before the National Energy Board ("NEB") and any other regulator that deals with other companies' tolls, facilities and rates which impact Enbridge.

Regulatory Affairs Services and Activities

3. The Regulatory Affairs Department ("Reg-Affairs") is responsible for ensuring Enbridge's and its customers interests are represented within all such proceedings. The majority of the department's time and resources are focused on the involvement and management of proceedings before the Board. Such proceedings include annual rate applications within either a cost of service or incentive regulation regime, quarterly gas commodity related rate changes, leave-to-construct applications, certificate of public convenience and necessity applications, franchise applications and renewals, storage designation applications, and various generic proceedings. Reg-Affairs works to ensure Company business strategies incorporate regulatory considerations and requirements, manages all regulatory proceedings, determines the revenue requirement of the Company within annual rate proceedings and in relation to gas commodity price changes within quarterly rate adjustment proceedings, determines the appropriate allocation of the resulting

revenue requirement amongst required rate classes, and is heavily involved in the working relationships with regulators and stakeholders.

4. In relation to annual rate applications, Reg-Affairs is responsible for determining the Company's annual revenue requirements, providing cost allocation, rate design and working cash allowance determinations, and developing deferral account clearing proposals for rate case proceedings. In addition, rates need to be adjusted to reflect the Board approved distribution revenues underpinning a given fiscal year. The derivation of rates is guided by the application of the user pay principle and a study of fully allocated costs supports the development of rates that reflect the cost of providing service to each customer rate class. Reg-Affairs also respond to emerging market demands and provide support to other internal departments involved in the rate application. The rate application process includes a number of tasks such as preparation of evidence, filing of applications, publishing Board Notices and Letters of Direction, participation in technical and settlement conferences, consultation with stakeholders and Board staff, review of and preparation of responses to interrogatories, witness preparations, hearing management, and argument. Reg-Affairs is also heavily involved in non-rate related applications as mentioned above.

5. Reg-Affairs is involved in and coordinates facilities applications and upstream regulatory interventions at the Board, the NEB, and FERC in respect of U.S. jurisdictions. The department analyzes toll/tariff and facilities related applications submitted by transmission and storage companies that impact the operations of the Company, and where appropriate, actively intervenes. These interventions assist the Company's overall objective to provide safe and reliable natural gas distribution and to understand the impacts on rates for all its residential, commercial, and industrial customers of the applications of such companies. Given that the

Company is one of the larger shippers on the TransCanada PipeLines' system, Reg-Affairs actively participates in negotiated settlements for tariffs and tolls, thereby helping to ensure that transportation rates and delivery charges to Ontario ratepayers are fair.

6. The NEB regulates the activities of Niagara Gas Transmission Ltd. and 2193914 Canada Limited (previously known as Consumers' Gas (Canada) Ltd.), affiliates of Enbridge. Reg-Affairs provides these affiliates with services related to the filing requirements for NEB applications, calculating tolls and obtaining NEB approval every year.

7. Reg- Affairs is the contact department for any complaints that arise under the Affiliate Relationship Code (the "ARC") and is responsible for meeting all requirements of the complaint process as prescribed by the Board. Reg-Affairs is also responsible for ARC compliance. Accordingly, it is involved in periodic internal compliance reviews and responds to any observations noted through these reviews. Reg-Affairs, on an on-going basis, develops communication materials to educate employees about the ARC.

8. The department maintains a relatively static workforce even with the level of miscellaneous and generic proceedings and consultatives requiring the department's involvement.

<u>Public & Government Affairs responsibilities</u>

9. The Public and Government Affairs Department ("P&GA") supports the business through customer communications, community relations, stakeholder and external communications, the office of the Ombudsman, research, government relations (particularly provincial and municipal), media relations, and other general public

relations activities such as external speeches and presentations, and crisis communications. P&GA works with other Company departments to promote a proactive program aimed at focusing communications on safety, customer care and issues management with stakeholder groups, including customers, customer interest groups, media outlets, municipal and provincial governments and industry.

10. P&GA's primary areas of accountability include: informing and influencing government on public policy issues related to the energy and gas sector by serving on various business association committees and task forces; advocating for the use of natural gas in the marketplace; producing and distributing customer information concerning safety, energy efficiency, environmental protection, community service, economic value and other topics; providing support for media relations by, for example, ensuring crisis communications preparedness; and, positively contributing to the Company's visibility and image as a key investor and contributor to the community. These activities lead to the development of positive relationships with key government stakeholders, highlighting the Company's commitment to the promotion of safe, clean, affordable and reliable natural gas.

<u>Services and Activities</u>

11. Franchise commitments require making investments in community projects that demonstrate a tangible benefit to customers, members of the community and Enbridge stakeholders. As part of this commitment, the Community Events Team provides in-kind support to more than 300 local community events in the Company's franchise area.

12. In order to meet stringent Customer Satisfaction targets, the office of the Ombudsman team of six Enbridge employees responds to customer inquiries by email, phone and in person. The Office responded to more than 6,700 inquiries in

2012. The office also identifies trends and issues that could impact customer satisfaction and works with the Customer Care department to identify solutions to improve customer experiences. The department as a whole also conducts regular survey research with customers to ensure that communications are understandable and meet customer needs.

13. The P&GA department ensures an appropriate level of crisis communication preparedness, including the development and maintenance of a communication manual and procedures, timely website updates as well as media training and participation in joint emergency simulation exercises with other utilities and first responders such as municipalities and local police and fire departments. The department posts information about significant service disruptions on the utility's website and often acts as lead media "spokesperson" in crisis and other situations, including incidents that impact natural gas equipment and appliances to ensure that affected customers have timely information. A P&GA representative is on call after hours to ensure timely communications after hours if required.

14. Delivering up-to-date information on rate changes, safety initiatives and service changes to customers in a timely fashion is one of the key priorities of the P&GA department. Customer Communications is responsible for designing billing inserts to ensure customers are kept informed of any and all changes. Common to most modern businesses, the Company has been responding to its customers' increasing usage and reliance upon the Internet to obtain timely information from Enbridge's website. As well, the P&GA department is aware of the importance of the new tools of communicating with customers by means of the various social media applications, such as Twitter and YouTube.

Witnesses: K. Culbert
P. Green
R. Small

The Company's use of these channels is in direct response to changes in the way that many of Enbridge's customers communicate.

15. As a result, in recent years, the Company has revamped and continues to consider its digital communications. The P&GA department has and continues to make important contributions to some of the information, including real time data that can be accessed from the Company's website, such as select current service interruptions and the deployment of a "dark" site that could be used to communicate with customers during a large-scale outage. Department members monitor Twitter on a proactive basis in part to address customer issues and concerns.

16. The role of the office of the Ombudsman has also continued to expand over the last few years in response to customer demand and the department's goal of working with customers to find satisfactory solutions, even in more complicated situations. A new Customer Service Centre was established to provide a more welcoming atmosphere to respond to confidential customer inquiries. In response to the service levels that customers demand, office of the Ombudsman staff also respond to customers with urgent issues outside of business hours.

<u>2013 - 2016 RPGA Budgets</u>

17. The 2013 Board Approved and 2014 through 2016 Budgets are shown in Table 1 below. The categories of costs which make up more than 90% of the business unit's budget are salaries and wages and outside services, Ontario hearing costs, and sponsorships, donations, and memberships. Salaries and wages are in relation to over 50 full time employees. Outside services are predominantly costs incurred in relation to customer and stakeholder communications (ie. bill inserts, media campaigns), in relation to safety, gas prices, and the gas marketplace. Ontario hearing costs are costs incurred by, or charged to, the Company for its

participation in Enbridge specific and generic proceedings, consultatives, or interventions. The costs include OEB costs, intervenor costs, external legal and consulting costs, etc. Over or under spending of Ontario hearing costs are charged to the Ontario Hearing Costs Variance Account (OHCVA). Sponsorships, donations, and memberships are costs incurred in relation to community investment initiatives, such as the Low-Income Energy Assistance Program ("LEAP") and for the Company's membership in various industry associations.

Table 1.

	2013 Board Approved ($000's)	2014 Budget ($000's)	2015 Budget ($000's)	2016 Budget ($000's)
Salaries and wages	5,045.3	4,830.9	4,938.7	4,826.7
Consulting	700.8	697.6	713.2	831.5
Outside services	4,093.1	4,150.0	4,242.5	4,461.1
Ontario Hearing Costs	7,342.5	8,000.0	6,000.0	6,000.0
Sponsorships, donations, and memberships	4,279.9	4,280.0	4,375.4	4,474.2
Training, travel, and other business expenses	369.2	350.1	358.0	364.2
Costs charged to an affiliate	(54.0)	(54.8)	(56.0)	(57.3)
Other	330.5	335.1	342.6	350.4
Total	$ 22,107.3	$ 22,588.9	$ 20,914.4	$ 21,250.8
FTE's	55	52	52	50

Productivity

18. As seen in the table above, RPGA's productivity is reflected within the forecast level of FTEs. RPGA will be required to meet existing, as well as evolving, regulatory and public-government affairs activity levels and it expects to do so with a decline in FTEs of 5 between 2013 and 2016.

Witnesses: K. Culbert
P. Green
R. Small

19. The FTE reduction will be managed in a way that does not negatively impact on the business requirements to be met by RPGA.

2014 RPGA Budget versus 2013 RPGA Board Approved Variance Explanations

20. Table 2 shown below, shows a comparison of the 2014 Budget and the 2013 Board Approved.

21. The ($0.2) million reduction in salaries and wages is the result of an FTE reduction of 2.7, resulting in a ($0.3) million decline, partially offset by annual wage increases of 2.2%, or approximately $0.1 million. The FTE reduction is anticipated as a result of Customized IR efficiencies and efficiencies expected from efforts to improve the customer experience.

22. The variance in Ontario Hearing Costs is the result of an anticipated increase in the complexity and time required for evidence preparation, responding to interrogatories and giving oral evidence within a the 2014-2016 rate setting process, versus that which was anticipated and required within Enbridge's 2013 cost of service rate proceeding. Commensurate with the anticipated required increase in the rate proceeding complexity and time is an anticipated increase in intervenor costs, consulting costs, and legal and other costs.

Table 2.

	2014 Budget ($000's)	2013 Board Approved ($000's)	Variance 2014 Budget vs. 2013 Approved ($000's)
Salaries and wages	4,830.9	5,045.3	(214.4)
Consulting	697.6	700.8	(3.2)
Outside services	4,150.0	4,093.1	56.9
Ontario Hearing Costs	8,000.0	7,342.5	657.5
Sponsorships, donations, and memberships	4,280.0	4,279.9	0.1
Training, travel, and other business expenses	350.1	369.2	(19.1)
Costs charged to an affiliate	(54.8)	(54.0)	(0.8)
Other	335.1	330.5	4.6
Total	$ 22,588.9	$ 22,107.3	$ 481.6
FTE's	52	55	(3)

2015 RPGA Budget versus 2014 RPGA Budget Variance Explanations

23. Table 3 shown below, shows a comparison of the 2015 Budget and the 2014 Budget.

24. The variance in Ontario Hearing Costs is the result of an anticipated reduction in the complexity of the main rate case proceeding in 2015, which as proposed within this rate application, will be a more mechanistic process with minimal required changes and therefore much less review and required time.

25. Salaries and wages are expected to increase due to an annual wage increase (2.2%), while other cost categories are expected to increase as a result of inflation.

Witnesses: K. Culbert
P. Green
R. Small

Table 3.

	2015 Budget ($000's)	2014 Budget ($000's)	Variance 2015 Budget vs. 2014 Budget ($000's)
Salaries and wages	4,938.7	4,830.9	107.8
Consulting	713.2	697.6	15.6
Outside services	4,242.5	4,150.0	92.5
Ontario Hearing Costs	6,000.0	8,000.0	(2,000.0)
Sponsorships, donations, and memberships	4,375.4	4,280.0	95.4
Training, travel, and other business expenses	358.0	350.1	7.9
Costs charged to an affiliate	(56.0)	(54.8)	(1.2)
Other	342.6	335.1	7.5
Total	$ 20,914.4	$ 22,588.9	$ (1,674.5)
FTE's	52	52	-

2016 RPGA Budget versus 2015 RPGA Budget Variance Explanations

26. Table 4 shown below, shows a comparison of the 2016 Budget and the 2015 Budget.

27. The ($0.1) million reduction in salaries and wages is the result of an FTE reduction of 2.0, resulting in a ($0.2) million decline, partially offset by annual wage increases of 2.3%, or approximately $0.1 million. The FTE reduction is anticipated to occur through attrition made possible by continued efforts to improve efficiency.

28. The variance in consulting and outside services is a result of an anticipated requirement of third party entities to assist in the preparing, planning and review of a potential future incentive regulation rate making model, reviews of the implications of any government policy changes and industry benchmarking practices in relation to customer and community communications.

Witnesses: K. Culbert
P. Green
R. Small

Table 4.

	2016 Budget ($000's)	2015 Budget ($000's)	Variance 2016 Budget vs. 2015 Budget ($000's)
Salaries and wages	4,826.7	4,938.7	(112.0)
Consulting	831.5	713.2	118.3
Outside services	4,461.1	4,242.5	218.6
Ontario Hearing Costs	6,000.0	6,000.0	-
Sponsorships, donations, and memberships	4,474.2	4,375.4	98.8
Training, travel, and other business expenses	364.2	358.0	6.2
Costs charged to an affiliate	(57.3)	(56.0)	(1.3)
Other	350.4	342.6	7.8
Total	$ 21,250.8	$ 20,914.4	$ 336.4
FTE's	50	52	(2)

Witnesses: K. Culbert
P. Green
R. Small

O&M – ENERGY SUPPLY AND POLICY

Mandate and Responsibilities

1. Enbridge Gas Distribution Inc.'s ("Enbridge" or the "Company") activities with respect to Energy Supply and Policy are driven by the need to have available, on both a peak day and an annual basis, the volume of natural gas required by all customers within Enbridge's franchise area. The department is organized into four main groups: Gas Supply Strategy, Gas Supply, Gas Control, and Gas Costs and Budgets.

Services and Activities

2. The Gas Supply Strategy group is responsible for forecasting future gas demand on a daily basis, looking at expected peak day, seasonal and annual requirements for the budget year and beyond, in order to develop supply plans to meet these requirements. Beyond the budget year, depending on future requirements, the supply plan provides a view of Enbridge's supply requirements for the next five to ten years so that future supply, transportation, and storage requirements can be understood. This also allows for the evaluation of an optimal supply portfolio when new or non-traditional services may become available. This group is also focused on the management of upstream transportation and storage issues which includes participating in industry task forces that may lead to changes in the services provided by upstream transportation companies or storage service providers and intervening in the regulatory proceedings of upstream service providers, when necessary.

3. Gas Supply activities include short-term supply planning, gas acquisition, and transactional services. The short-term supply planning looks at expected supply

requirements for the remainder of the gas year, with a particular focus on the current and next month. Demand requirements are balanced against the available supply options to ensure adequate supply will be available to meet customer demand on an annual basis. Based on the short-term plan, gas is acquired in the marketplace from authorized counterparties. Transactional services activities work to optimize the value that ratepayers receive for storage assets or transportation contracts when they are not being fully utilized to meet the needs of utility ratepayers on the day. Storage capacity or transportation services are sold into the marketplace at market prices. The revenues generated by these activities are shared between ratepayers and the shareholder.

4. The Gas Control group is responsible for forecasting demand for the coming days and adjusting supplies for shifts in demand during the course of the day within the different franchise areas. This requires ensuring that appropriate volumes of gas are nominated on the various transportation systems on which Enbridge has contracted capacity. Gas Control also has responsibility for monitoring all of the system operating pressures within the distribution system to ensure its safe operation.

5. The Gas Costs and Budgets group is responsible for the preparation of the gas cost budget to be filed with the Ontario Energy Board (the "Board"), as well as any QRAM filings. Regulatory support for gas costs approval is provided in the form of evidence, interrogatory responses and testimony, if necessary. Another function of this group is the verification and reconciliation of gas supply commodity, transportation, and storage invoices to ensure accurate and timely payment of those invoices. In addition, Gas Costs and Budgets staff generate the monthly gas cost information which is required by Finance to book the necessary entries to the

general ledger. This includes amounts to be booked to the various gas supply deferral accounts, including the Purchase Gas Variance Account ("PGVA") and any analysis required for the purpose of QRAM filings.

2014 -2016 Budgets

6. Table 1 shows the 2013 Board Approved as well as 2014 - 2016 Budgets.

Table1
2013 - 2016

	2013 ($000's)	2014 ($000's)	2015 ($000's)	2016 ($000's)
Salaries and wages	3,300	3,407	3,519	3,635
Outside Services / Consulting	179	171	174	177
Travel & Entertainment & Other Business Expenses	298	287	292	296
Internal Allocations & Recoveries	450	378	363	340
	$ 4,227	$ 4,243	$ 4,348	$ 4,449
FTEs	32	32	32	32

7. Salaries and wages represent the majority of the O&M costs and are in relation to 32 required full time employees. The Gas Supply and Gas Control groups (22 of the 32 total full time employees) are located in Alberta where salaries and wages are subject to the cost pressures of the very competitive Alberta labor market.

8. Outside Services/Consulting is in relation to the cost of external expertise required in support of regulatory work and analysis of market conditions when forecasting and developing budgets and supply requirements.

9. Travel & Entertainment and Other Business Expenses are comprised of several elements. Along with the geographic dispersion of the group, which leads to

travel, members of the group must travel for industry meetings as well as regulatory proceedings related to NEB regulated pipelines on which Enbridge takes service. This group of expenses also includes employee development costs and industry memberships.

10. Internal Allocations and Recoveries reflect affiliate charges for Supervisory Control and Data Acquisition ("SCADA") services (systems used to monitor and control gas flows on Enbridge's distribution system) offset by recoveries for services provided to other Enbridge affiliates.

2014 Budget vs. 2013 Board Approved Variance Explanation

11. Table 2 shows a comparison of the 2014 Budget and the 2013 Board Approved.

12. 2014 Budget is flat versus 2013 Board Approved. An increase due to wage inflation is offset by a decrease in other expenses representing an effort to reduce overall costs. The $0.1 million increase in salaries and wages results from an average wage increase that is above the Company average, driven by the large number of staff located in Alberta discussed earlier.

Table 2
Variance Between 2014 Budget and 2013 Board Approved

	2014 ($000's)	2013 ($000's)	Variance 2014 vs. 2013
Salaries and wages	3,407	3,300	107
Outside Services / Consulting	171	179	(8)
Training, Travel & Entertainment & Other Business Expenses	287	298	(11)
Internal Allocations & Recoveries	378	450	(72)
	$ 4,243	$ 4,227	$ 16
FTEs	32	32	-

2015 Budget vs. 2014 Budget Variance Explanation

13. Table 3 shows a comparison of the 2015 Budget and the 2014 Budget.

14. The overall cost increase of $0.1 million increase in salaries and wages results from an average wage increase that is above the Company average driven by the large number of staff located in Alberta as discussed earlier.

15. Internal Allocations & Recoveries are lower as it is expected that Gas Control will be able to generate an offset to O&M through additional SCADA services which the department will provide to affiliates. The expected start time of these additional SCADA services is the second half of 2015.

Table 3
Variance Between 2015 Budget and 2014 Budget

	2015 ($000's)	2014 ($000's)	Variance 2015 vs. 2014
Salaries and wages	3,519	3,407	112
Outside Services / Consulting	174	171	3
Training, Travel & Entertainment & Other Business Expenses	292	287	5
Internal Allocations & Recoveries	363	378	(15)
	$ 4,348	$ 4,243	$ 105
FTEs	32	32	-

2016 Budget vs. 2015 Budget Variance Explanation

16. Table 4 shows a comparison of the 2016 Budget and the 2015 Budget.

17. The overall cost increase of $0.1 million increase in salaries and wages results from an average wage increase that is above the Company average driven by the large number of staff located in Alberta discussed earlier.

18. Internal Allocations & Recoveries are lower as they reflect the full-year effectiveness of the offset to O&M resulting from the expected additional SCADA services to be provided to affiliates starting mid-2015.

Table 4
Variance Between 2016 Budget and 2015 Budget

	2016 ($000's)	2015 ($000's)	Variance 2016 vs. 2015
Salaries and wages	3,635	3,519	116
Outside Services / Consulting	177	174	3
Travel & Entertainment & Other Business Expenses	296	292	4
Internal Allocations & Recoveries	340	363	(23)
	$ 4,449	$ 4,348	100
FTEs	32	32	-

Productivity

19. The Energy Supply and Policy O&M budgets reflect forecasted productivity realization. The natural gas supply picture is changing rapidly compared to the past when there were few options available for gas and transportation services. The Department, through its experience and expertise, is forecasting to hold FTEs constant despite the work of the department becoming increasing more complex. As a result, the Department will have to find ways to be efficient in the delivery of its required work.

The Department also intends to expand recoveries from affiliates through increased monitoring and nominations services delivery thereby helping to offset O&M cost pressures.

NON-DEPARTMENTAL O&M EXPENSES

Mandate and Responsibilities

1. Within Enbridge Gas Distribition Inc's ("Enbridge" or the "Company") Operation and Maintenance ("O&M") Budget there are certain costs that are not department specific and as such are not included within the costs of any one department. The purpose of this evidence is to provide details of these non-departmental costs.

2. The non-department specific costs are comprised of executive management team ("EMT") salaries and their administrative support costs, training and development, travel, and trade memberships and director fees.

Services and Activities

3. This EMT provides strategic leadership to Enbridge and has overall responsibility for the day to day operations of the Company. This includes ensuring Enbridge achieves financial and operational results as set through the use of a "scorecard". See Exhibit D1-16-1 for a description of the scorecard metrics. All Enbridge EMT members and their administrative support costs are contained within budget.

Witnesses: M. Lee
S. Trozzi

2013, 2014, 2015 and 2016 Budget

Table 1

Non-Departmental
Operating and Maintenance Expense
2013, 2014, 2015 and 2016 Budget

Line No.	Particulars ($ 000's)	Budget 2013	Budget 2014	Budget 2015	Budget 2016
		$	$	$	$
1	Salaries and Wages	2,869	2,984	3,050	3,119
3	Costs Charged to Affiliates	(60)	(61)	(62)	(63)
4	Other	755	666	681	696
6	Eliminations of Donations	(10)	0	0	0
7	Total Gross Operating and Maintenance Expense	3,554	3,589	3,669	3,752
8	FTE	15	15	15	15

Components of the 2014 Budget

4. The 2014 Budget for Non-Department specific costs is $3.6 million as illustrated in Table 1 above.

5. EMT salaries and wages, including administrative support personnel, to be incurred during the normal course of business are budgeted at $3.0 million.

6. Compensation levels are competitively based on market conditions that reflect the

local labour market in which the Company competes for talent. Enbridge has a defined comparator group of companies comprised of oil, gas, and utility companies and other large Canadian organizations with whom Enbridge competes for talent and in which compensation surveys are conducted annually. The pay philosophy that Enbridge utilizes is to target total cash compensation at the 50th percentile of the market. Enbridge ensures that compensation for employees is consistent with its pay philosophy and is competitive and appropriate.

7. Costs Charged to Affiliates compensate the Company for its executives spending time on affiliate work, including attendance at affiliate board meetings for St. Lawrence Gas, Gazifere Inc., Niagara Gas Transmission and Enbridge Gas New Brunswick. $0.06 million is budgeted to be charged to affiliates in 2014.

8. Other expenses, budgeted at $0.7 million, include material and supplies, employee training and development expenses, outside services, travel and trade and civic membership fees.

Variance Explanation 2014 Budget vs 2013 Budget

Table 2

Non-Departmental
Operating and Maintenance Expense
2014 Budget versus 2013 Budget

Line No.	Particulars ($ 000's)	Budget 2014	Budget 2013	2014 Test Year vs. 2013 Budget
		$	$	$
1	Salaries and Wages	2,984	2,869	115
3	Costs Charged to Affiliates	(61)	(60)	(1)
4	Other	666	755	(89)
6	Eliminations of Donations	0	(10)	10
7	Total Gross Operating and Maintenance Expense	3,589	3,554	35
8	FTE	15	15	0

9. EMT salaries and wages decrease by $0.1 million. The 2013 Budget included $0.5 million for EMT benefits which was moved to be included in Human Resources costs to keep all benefit costs together. After considering the move of EMT benefit costs, salaries are relatively flat compared to the 2013 Budget due to the move of a position to Operations, being offset by salary changes.

10. Other expenses, such as travel, materials and supplies, decrease by $0.1 million.

Witnesses: M. Lee
S. Trozzi

Variance Explanation 2015 Budget vs 2014 Budget

Table 3

Non-Departmental
Operating and Maintenance Expense
2015 Budget versus 2014 Budget

Line No.	Particulars ($ 000's)	Budget 2015	Budget 2014	2015 Budget vs. 2014 Budget
		$	$	$
1	Salaries and Wages	3,050	2,984	66
2	Costs Charged to Affiliates	(62)	(61)	(1)
3	Other	681	666	15
4	Total Gross Operating and Maintenance Expense	3,669	3,589	80
5	FTE	15	15	0

11. The 2015 Budget for Non-Department specific costs is $3.7 million. This is an increase of $0.08 million from the 2014 Budget total.

12. Salaries and wages in the Non-Departmental 2015 Budget increases from the 2014 Budget figures by $0.07 million due to base salary wage increases.

13. Other expenses, such as travel, materials, supplies, and director fees are not forecasted to change other than business as usual and therefore are forecasted to increase by inflation only.

Witnesses: M. Lee
S. Trozzi

Variance Explanation 2016 Budget vs 2015 Budget

Table 4

Non-Departmental
Operating and Maintenance Expense
2016 Budget versus 2015 Budget

Line No.	Particulars ($ 000's)	Budget 2016	Budget 2015	2016 Budget vs. 2015 Budget
		$	$	$
1	Salaries and Wages	3,119	3,050	69
2	Costs Charged to Affiliates	(63)	(62)	(1)
3	Other	696	681	15
4	Total Gross Operating and Maintenance Expense	3,752	3,669	83
5	FTE	15	15	0

14. The 2016 Budget for Non-Departmental specific costs is $3.8 million. This is an increase of $0.08 million from the 2015 Budget total.

15. Salaries and wages in the Non-Departmental 2016 Budget increases from the 2015 Budget figures by $0.07 million due to base salary wage increases.

16. Other expenses, such as travel, materials, supplies, and director fees are not forecasted to change other than business as usual and therefore are forecasted to increase by inflation only.

Witnesses: M. Lee
S. Trozzi

ENBRIDGE GAS DISTRIBUTION

SCARBOROUGH, ONTARIO

NET SALVAGE STUDY

REPORT ON REVIEW AND ANALYSIS AND REVIEW OF ALTERNATIVE NET SALVAGE CALCULATION METHODS AND PROCEDURES

JUNE 2013

Gannett Fleming

Excellence Delivered As Promised

Gannett Fleming

Excellence Delivered ***As Promised***

June 11, 2013

Enbridge Gas Distribution
PO Box 650
Scarborough, Ontario
M1K 5E3

Attention: Mr. Narin Kishinchandani
Vice President, Finance

Ladies and Gentlemen,

Pursuant to your request, we have conducted a review and analysis of net salvage calculation methods and procedures. Our report presents a description of the alternative methods reviewed, and provides a recommendation to use a Constant Dollar method. The method was applied through application of the Constant Dollar approach to the accounts in which a net salvage percentage is applicable.

This report also includes a re-calculation of the depreciation accrual rates in the accounts impacted by this review in order to provide for the appropriate level of depreciation expense in the company's revenue requirement. Additionally, this report provides for an implementation schedule over a five year period to true up the accumulated depreciation account variances caused by the implementation of the recommended methods.

Respectfully submitted,

GANNETT FLEMING CANADA ULC.

LARRY E. KENNEDY
Vice President

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PART I. INTRODUCTION

PART I. INTRODUCTION

SCOPE

This report sets forth the results of a study undertaken by Gannett Fleming Canada ULC (“Gannett Fleming”) of methods and procedures that could be used in the determination of net salvage percentages used in the calculation of depreciation rates for Enbridge Gas Distribution (“Enbridge), and provides for a Constant Dollar Net Salvage (“CDNS”) approach to the calculation of the net salvage percentages.

Part I, Introduction, contains statements with respect to the scope of the report and the basis of the reviews. Part II, Alternatives Reviewed, presents the various alternative methods that Gannett Fleming viewed that may be reasonably appropriate for the development of net salvage percentages to be used by a regulated natural gas utility such as Enbridge. Part III, Results of Review and Recommendations, presents a summary of annual depreciation, and calculated accumulated depreciation requirements resulting from the application of the recommendations contained in this report. Also included in Part III, is a proposed procedure for the implementation of the recommended CDNS method over a 5-year period.

BASIS OF THE REVIEW

Gannett Fleming has completed this assignment in two separate phases. The first phase included a high level review of the physical procedures used in the removal of distribution mains and distribution services. Additionally the historic costs for removal of distribution mains and services were compared to the costs of the anticipated current and future costs for removal. A summary of the findings resulting from the Phase 1 review is attached as Appendix 1 to this report.

Upon completion of the first phase of the assignment, Enbridge advised Gannett Fleming that there was sufficient reason to believe that the Phase 2 work should proceed. Phase 2 included a more detailed review of the alternative methods for the calculation of net salvage percentages and included the testing of the findings on the accounts with the largest requirement for future costs of retirement, namely Account 475.00 - Distribution Mains (both coated steel and plastic) and Account 473.00 - Distribution Services. Lastly, the Phase 2 work involved the application of the recommended Constant Dollar Method to all accounts for which a net negative salvage percentage was estimated in the 2011 Gannett Fleming Depreciation study.

RECOMMENDATIONS

Based on the review, Gannett Fleming considers that a Constant Dollar approach to the calculation of net salvage percentages is appropriate. With this approach, all historic influences of inflation are removed from the calculations by bringing the original cost of the retirement plant to a current dollar level, and further by normalizing the historic costs of removal to a 2010 cost base. In this manner a removal cost estimate, net of inflationary impacts can be determined. The normalized cost of removal is then inflated through to the end of the estimated composite remaining life of the account using an independent estimate of long term inflation, and then discounted back to 2010 to recognize the time value of the funds collected over period of time from now through the end of the estimated remaining life.

PART II. ALTERNATIVES REVIEWED AND RECOMMENDED APPROACH

PART II. ALTERNATIVES REVIEWED AND RECOMMENDED APPROACH

ALTERNATIVES REVIEWED

Background.

Gannett Fleming has completed a number of full and comprehensive depreciation studies, including a study completed in 2011 on the assets in service through December 31, 2010 (the "2011 study"). In each of the studies, a large net negative salvage percentage has been identified related to the estimated costs required for the future retirement of assets in a number of the Enbridge accounts. Additionally, a large fund of over $700 Million related to the funds required for future removal of assets has accumulated. Based on the impacts that the large annual requirement for net salvage is causing in the company's revenue requirement (over $50 Million annually), and on the attention that the accumulated fund is receiving in reviews of the company's financial statements, Enbridge asked Gannett Fleming to review the assumptions and concepts used in the net salvage calculations and to determine if, in fact, the actual requirements are as large as the depreciation studies have been indicating.

The requested reviewed was separated into two phases as follows:

- Phase 1 to review the potential that the currently used net salvage percentages may not be appropriate for the company's two largest accounts (Distribution Mains and Distribution Services), giving consideration to the increased use of newer generation plastic pipes, and potential changes in installation and removal/abandonment procedures; and
- Phase 2 to undertake a review of alternative methods and detailed calculations of

net salvage percentages. Phase 2 was to be completed if the Phase 1 review indicated that the continued use of the "Traditional Approach" as used in the previous depreciation studies may not be reasonable.

A summary report of the findings of the Phase 1 review is attached as Appendix 1 to this report. Importantly, the Phase 1 review found that the Net Salvage rates related to the recovery of future costs of removal for the Distribution Mains account may be too large. The Phase 1 review also concluded that the net salvage rates related to the Distribution Services account was reasonable or a bit too low. However, the Phase 1 findings did conclude that alternative approaches should be investigated. Enbridge asked Gannett Fleming to complete the work identified as the Phase 2 review.

<u>Current Approach to Net Salvage</u>.

The approach used to calculate the net salvage percentages in the 2011 study (and all previous Enbridge depreciation studies) as completed by Gannett Fleming incorporated the use of the "Traditional Method" of net salvage analysis. The use of the Traditional Method of net salvage analysis is consistent with the method used by most depreciation analysts in studies throughout North America, including the most recent study completed by Fosters and Associates in the recent Union Gas study filed with the Ontario Energy Board.

In the estimation of the net salvage percentages developed using the traditional approach Gannett Fleming includes the following steps:

1. The annual retirement, gross salvage and cost of removal transactions are extracted from the plant accounting systems over a period of observation – normally at least a 10 year period.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. A net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band.
4. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
5. Each account is then compared to the net salvage percentage currently approved and compared to peer utility companies. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Gannett Fleming, a net salvage percentage is determined for each account.
6. The net salvage percentage is then used in the depreciation rate calculations in the technical update.

The traditional method of analysis recognizes that, as the plant is removed a number of years following its installation, the cost of removal is usually greatly increased due to the impacts of inflation. As such an historic ratio of net salvage to original cost dollars retired dollars has an inherent level of inflation built in, but should not be considered to be fully time synchronized.

Gannett Fleming has reviewed the historic levels of inflation over the observation period of the net salvage analysis, and has determined that the historic inflation rate was 3.32% over the period, including a period in the 1980's of abnormally high inflation. In part, the review of the net salvage statistics was impacted by the higher than normal historic inflation rates.

Alternative Approaches Reviewed.

Based on our experience, Gannett Fleming viewed that three alternative approaches could be considered, as follows:

- A "Pause Approach" wherein the annual accrual related to the funding of the accumulated reserve for future removal of plant could be suspended for a short period of time, while the accumulated reserve is allowed to be drawn down;
- Application of differing net salvage percentages to original cost of plant currently in service for each specific installation vintage; and
- Application of a "Constant Dollar" approach wherein all historic transactions are revalued to a current cost to allow for a current cost percentage of net salvage with all impacts of historic inflation removed. The current cost estimate is then inflated using unique estimates for future inflation.

A review of each of these three alternatives follows:

Pause Approach - The use of the pause approach would be appropriate in the circumstances where the accumulated reserve for the costs of future removal of assets is considered to be in a surplus or over-funded position. In this manner the accumulation of funding can be suspended until such time as the reserve fund becomes in balance without compromising the projected ability of the utility to fund its future costs of removal. The use of this approach requires a significant amount of monitoring and frequent reviews and ability to restart the funding of the cost of removal fund.

This approach has been used by Canadian regulated utilities. Namely, the collection of net salvage was paused through a period of a negotiated settlement from 2006 through 2012 by Terasen Gas (now FortisBC Energy Inc.). The British Columbia Utilities Commission allowed re-instatement of the funding of future costs of removal in April 2012 as part of the most recent General Rate Application following the expiration of the negotiated settlement period. However, this re-instatement of the funding was met with a significant level of opposition.

In a recent application before the Northwest Territories Public Utilities Board, the Northwest Territories Power Corporation requested a pause to the net salvage recovery, given their very significant over-recovery to date of the required net salvage reserve.

In addition to the above two precedents, Gannett Fleming is aware of three Decisions where a Canadian Regulator has ordered a pause approach, notwithstanding an application of the utility for continued funding of net salvage . In a 2005 Decision, the BCUC ordered BC Hydro to cease funding its "Fund for Site Restoration Costs"

("FRSR") until such time as the current fund is drawn down to zero and thereafter to include the costs of retirement and site restoration in the annual operating costs of the company. In a 2007 Yukon Regulatory Board Decision relating to an Application of the Yukon Energy Corporation ("YEC"), the Board denied the YEC request for funding its reserve for future net salvage requirements and ordered that the fund should be significantly drawn down before any future funding requests would be considered. Additionally, the Yukon Regulatory Board in a 2008 Decision relating to an application of the Yukon Electric Company Limited ("YECL"), ruled in a very similar fashion as it did in the YEC proceeding and denied the YECL funding of the reserve for net salvage requirements until such time as the fund is materially reduced.

As noted in the Phase 1 review findings (Appendix 1 to this report) the distribution mains account may be in a position for which this approach could be used, however, the distribution services account cannot be considered as over-funded at this time. Furthermore, Gannett Fleming views that this approach carries a significant level of regulatory risk. While the pausing of the net salvage funding will have a toll reducing impact in the short term, and is likely to receive regulatory approval due to the toll reducing influence, the resumption of the funding in future years will have the opposite effect of a toll increasing impact. As such, the resumption of the required level of funding in future applications will likely face a significant level of opposition at that time.

Gannett Fleming also notes that the use of the pause approach is not consistent with the regulatory concept of generational equity. In this approach, the current toll payers would receive a holiday from any amount of funding the future removal of the assets that are in use and contributing to the utility service used by the current toll payer. Conversely, the future toll payers will be asked to pick up some of the burden when the recovery is reinstated.

Given that Gannett Fleming does not view that the current level of the reserve for the funding of cost of removal is materially over-funded, and further giving recognition to regulatory risk of significant opposition when funding is resumed and to the generational inequity caused by the pause approach, Gannett Fleming does not view that this approach is an appropriate option for Enbridge at this time.

<u>Use of Differing Net Salvage Percentages to Various Installation Years</u> - Both of the accounts for which there are materially high levels of net salvage requirements have gone through a number of eras of pipe types (cast iron, bare steel, coated steel, early generation plastic, and more recent generations of plastic), installation techniques and procedures. Given this variety of pipe composition and installation procedures, Gannett Fleming considered that it may be reasonable to assume that the procedures used for the removal or abandonment of the pipe may also vary by era of installation. In the circumstance that the abandonment or removal procedures and costs would vary based on the age or installation era, varying net salvage percentages could be applied to the original costs in installation of the varying vintages in the depreciation rate calculations. As such the adequacy of the net salvage reserve could then be retested to determine if a reduced amount of annual accrual would be appropriate.

As indicated in the Phase 1 review findings attached as Appendix 1 to this report, it is the view of the operations staff that the procedures followed in the abandonment or removal of Distribution Mains and Distribution Services is not materially different for the newer generations of plastic and coated steel pipes as compared to the older eras of cast iron and bare steel pipe. As such, the amount of required funds in future years does not change based on the expectation that in future years, the newer eras of pipe will be retired rather than the current situation where the historic retirement activity has largely related to older eras of pipe types.

Given that the future procedures used for pipe abandonment and removal will be largely similar to the historic practices, Gannett Fleming did not explore this option any further during the Phase 2 review.

Use of a Constant Dollar Approach - There are two components to the development of an appropriate future net salvage percentage for mass property accounts. Firstly, an estimate of the current net cost of removal of facilities is developed. The ratio of net salvage costs to the original cost of plant retired is developed and used as one indicator of the current estimated cost of removal. However, as the plant is removed a number of years following its installation, the cost of removal is usually greatly increased due to the impacts of inflation. In particular, the cost of removal is almost exclusively labour-related. The inflationary pressures of the Ontario labour market, due to numerous and unique labour fluctuations have a dramatic impact on the net cost of removal percentages. As such a historic ratio developed by comparing cost of removal expenditures to original cost dollars retired dollars has an inherent level of inflation built in, and cannot be considered to be time synchronized.

Once the historic indications of net costs of retirement are determined, the depreciation analyst can compare the historic indications of the net costs to remove plant, to the costs of the engineering projects currently being undertaken, or planned to be undertaken in the near future. However, it is normal to make adjustments to the historic indications and in many circumstances the historic indications of net salvage costs are adjusted to reflect the projects currently underway.

The second component required in the future estimation of costs of removal, is to determine the cost required at the time of forecast retirement. Once the current estimate of the net costs of removal are established, the current estimate needs to be adjusted to recognize the impacts of inflation over the period from the current time, to the estimated remaining life of the account. For the purposes of this review a future inflation rate of 2.00% was used in the calculations included in this report.

A comparison of the use of testing a constant dollar method, and the “traditional” methods of estimating future net salvage proceeds can be made. In making such a comparison, the manner in which both methods determine the current estimate of costs of removal, and the manner in which the current estimate should be inflated to the end of the estimated remaining life of the asset, require review. In the development of the historic net salvage ratio of realized costs of retirement as a percent of the original cost dollars retired using traditional methods, as discussed above, no adjustments are made, and the inherent historic rate of inflation remains in the ratio. In comparison, in a constant dollar method, each of the transactions is brought forward to the current point in time, thereby putting all transactions at a common point in time. In the circumstances of this review the historic transactions were re-based to year 2010 dollars. As a result of this time-synchronization, the resultant net salvage ratio has all impacts of inflation removed.

In developing the inflation estimate to be applied to the current cost of removal estimate, the constant dollar method requires the application of a forward looking estimate of the rate of inflation for labour costs connected with the retirement of facilities. The rate of inflation for labour costs is the primary driver of the future costs of retirement, and the current cost estimate has had all impacts of inflation removed. In comparison, when using the traditional method, because the current cost estimate is inclusive of historic rates of inflation, no further adjustment is made. Under the traditional method, a rate of inflation is used based on the historic rates of inflation that would have occurred between the points in time from the original installation of an asset and the time at which it was removed. Use of the historic rates of inflation that are not indicative of future rates of inflation produces an unrealistic forecast of future costs of removal. However, a constant dollar method utilizing forecasted inflation rates that were reviewed with a specific labour focus will produce more accurate cost of removal forecasts.

A comparison of a constant dollar method to the traditional method indicates that:

- Both methods rely on the historic trends of realized costs of retirement as a percentage of original costs retired;
- Both methods should be compared against the currently budgeted removal projects; and
- Both methods use a rate of inflation to estimate the future costs of retirement at the end of the average remaining life of the account.

In addition to the above comparison of the similarities, a comparison of the differences in the two methods should also be analyzed:

- The current cost estimate developed using the constant dollar method, utilizes a forward looking rate of inflation that is based on the current long term economic data. The traditional method uses the imbedded historic rates of inflation that may have been caused by historic events that may or may not be repeated; and

- The comparison of the current cost of removal to currently budgeted projects in the constant dollar method, is truly a comparison made in today's dollars, whereas the comparison made utilizing the traditional methods have a significant amount of time-synchronization issues that require adjustment.

Gannett Fleming notes that the constant dollar approach is consistent with a limited amount of historical regulatory precedent. A constant dollar approach was used by TransAlta Utilities Limited for many years, and received specific approval by the Alberta Energy and Utilities Board (now the Alberta Utilities Commission) in EUB Decision U97065. It was noted that the constant dollar method would properly allocate the estimated retirement costs over the entire service life of the asset. However, it should also be noted that in a 2002 EUB Decision relating to AltaLink, the EUB denied the continued use of the constant dollar approach, indicating that it placed too much emphasis on the forecasting of the future inflation rate and on the choice of historic inflation rates, which required specific labour related rates. Additionally, in a 2010 Decision the AUC again denied the use of a constant dollar approach in an application by AltaLink. In the 2010 decision the AUC specifically noted the benefits of a constant dollar approach but were not convinced that circumstances had sufficiently changed enough to reverse their 2002 Decision.

In order to recognize that the funds collected in current periods will not be expensed until potentially many years into the future, a discounted cash flow calculation is required. In this manner, the fact that the utility has received the benefit of the funds as working capital through the inclusion of the requirement into the current period revenue requirements, Gannett Fleming discounted the future requirements by the current long term Canadian AAA bond rate. This discount rate and calculation is consistent with the requirements of Asset Retirement Obligations in Canadian GAAP. As such, Gannett Fleming included a discount rate of 2.38% in the calculation of this method.

Gannett Fleming views that the constant dollar approach potentially may result in net salvage percentages that will more accurately reflect the future funding requirements. Additionally, Gannett Fleming views that it is the most reasonable alternative approach to the continued use of the traditional approach. As such, Gannett Fleming proceeded to test a constant dollar approach to the Distribution Mains and Distribution Services accounts to determine the overall depreciation expense reductions. The results of the testing are provided in Part III – Results of this report. Based on the results of this testing, Enbridge agreed with the Gannett Fleming recommendation to apply the Constant Dollar Method to all accounts where a net negative salvage percentage was identified in the 2011 Depreciation study.

In order to provide the depreciation expense impact a revised Schedule 1 is provided in Section III of this report. The attached Schedule 1 summarizes the original cost, booked accumulated depreciation reserve, the required future depreciation accruals, the estimated composite remaining life, and the required annual depreciation accrual for each account. Additionally, a copy of the detailed calculations is provided in Appendix 2 – Detailed Calculations to this report.

PART III – RESULTS AND RECOMMENDATIONS

PART III – RESULTS AND RECOMMENDATIONS

The primary product of this report is a recommendation to use a constant dollar approach in the development of net salvage percentages. Gannett Fleming views that the CDNS approach for calculation of the net salvage percentages represents a reasonable alternative approach to the currently used traditional approach.

In making this recommendation, Gannett Fleming has considered that a Constant Dollar Net Salvage ("CDNS") approach to the calculation of net salvage percentages is the preferred approach to more accurately reflect the going forward requirement of amounts that Enbridge requires for its net salvage provisions. Specifically, the Gannett Fleming recommendation is based on the following:

1. The ability of the CDNS method to normalize the unusually high periods of historic inflation out of the calculations in favor of an estimated and separately developed estimate of future inflation;
2. The CDNS approach specifically utilizes the estimated remaining life of assets currently in service. The plastic pipes installed in more recent periods may have a longer life than the bare steel and cast iron pipes of the past. Therefore, when depreciation studies identify a change in the remaining life estimates, the collection of net salvage will likewise be adjusted to reflect the new estimates.
3. The enhanced ability of the CDNS approach to be compared to current budget estimates related to the retirement and removal of assets.

4. The recognition that the majority of the funds collected to date will not be spent until future periods.

In order to provide the magnitude of the change in the net salvage percentages that may be realized using a constant dollar approach, Gannett Fleming first calculated net salvage percentages for the Distribution Mains and Distribution Services accounts using a constant dollar approach. Gannett Fleming notes the following results of this testing:

- Account 473.00 – Distribution Services - The net salvage percentage declines from a negative 45% using the traditional approach to a negative 28% using the constant dollar approach.
- Account 475.21 – Distribution Mains (Coated Steel) - The net salvage percentage declines from a negative 65% using the traditional approach to a negative 55% using the constant dollar approach.
- Account 475.30 – Distribution Mains (Plastic) - The net salvage percentage declines from a negative 85% using the traditional approach to a negative 55% using the constant dollar approach.

Based on the results of the above testing, and the acceptance by Enbridge, the Constant Dollar Method was applied to all accounts where a net negative salvage percentage was recommended in the 2011 depreciation study. Attached as Schedule 1 of this report are the revised 2011 depreciation study results incorporating revised net salvage percentages derived using a constant dollar approach for the Distribution Mains and Distribution Services accounts (based on the lives as determined in the negotiated settlement process). Attached as Appendix 1 to this report are the findings from the

Phase 1 review of this assignment. Attached as Appendix 2 to this report are the detailed calculations relating to the depreciation expense for each account impacted by the recommendations contained in this report.

Implementation of the CDNS Approach

It is recommended that the implementation of the CDNS approach be incorporated through inclusion of the net salvage percentage as determined by the CDNS approach into the depreciation rate calculations as provided in Appendix 2 to this report, and as summarized in Schedule 1. A comparison of Schedule 1 of this report and a similar calculation based on the net salvage percentages and average service life estimates as agreed to in the negotiated settlement related to the 2013 Rate Application indicate the implementation of the CDNS approach results in an annual depreciation expense decrease of approximately $33.5 million. The decrease in depreciation expense of $33.5 million is comprised of two components. Firstly an annual depreciation expense decrease of $26.9 million results from the lower expectation of future net salvage costs. Secondly, the depreciation rates as summarized in Schedule 1 were calculated on a remaining life basis[1], which has been the long standing approach to calculating depreciation expense in Ontario. The remaining life calculations include an additional annual refund of approximately $6.6 million due to the estimated over collection to date caused by the conversion to the CDNS approach. The annual refund of $6.6 million represents this amortization of the excess accumulated

[1] With the Remaining Life Basis the Net Book Value (as adjusted for the future net salvage requirements) is divided by the composite remaining life of each account. Therefore historic over or under collections of accumulated depreciation caused by changes in estimates related to average service life, Iowa Curve or net salvage percentages are accrued over the composite remaining life of the account.

depreciation over the composite remaining life of each account caused by the conversion to the CDNS approach. The implementation approach recommended by Gannett Fleming in this report maintains this Remaining Life basis while allowing for a faster return of the excess depreciation expense collected.

Gannett Fleming has calculated that if the CDNS method had been used since inception for all accounts, the accumulated depreciation related to net salvage would have been $292.8 million less than the current amount. Absent any additional adjustment mechanism, an annual adjustment within the depreciation rates of $6.6 over the composite remaining life of each account would provide for the true up of the historic accumulated depreciation balance. However, this report provides for the adjustment of the complete $292.8 million over a 5 year period. Consequently, the amounts for additional adjustment must consider the annual amount of $6.6 million (or $33 million over the test period), that is already included in the depreciation rates attached as Schedule 1 to this report resulting in a need for an additional return of $259.8 million. In this manner the impacts of the change in approach will be recovered over the composite remaining life of the accounts where a net salvage rate is considered appropriate.

It is noted that the conversion to the CDNS method is a change in methodology resulting in a change in the net salvage percentage. In comparison, historic changes to the net salvage percentages have resulted from only a change in the estimated percentage rather than from the change in the approach to determine the percentage. In this manner, it is reasonable to consider an implementation period wherein the accumulated depreciation variances between calculated accumulated depreciation requirements and the actual booked accumulated depreciation balances resulting from the change in methodology are trued-up over a shorter period than the composite remaining life of each account.

Gannett Fleming has worked with Enbridge to recommend a plan for the transition to the CDNS method in a manner that is fair to all toll payers. Based on our discussions we recommend, that in this specific circumstance, a true-up of accumulated depreciation variances related specifically to the implementation of the CDNS approach over a five-year period is appropriate. Gannett Fleming notes that the portion of a required accumulated depreciation true-up that is specifically required due to the change in calculation methods can be isolated and trued-up over a period other than the composite remaining life of each account.

Typically Gannett Fleming recommends that all variances caused by factors such as changes in life estimate, gains/losses on retirement, etc. be trued up over the composite remaining life of the account consistent with the long standing practice in Ontario. However in the case of a fundamental change in the methodology or policy, Gannett Fleming recommends truing up the variance specific to the change in method or policy over a shorter period. It is noted that this unique adjustment is a required adjustment from the typical true-up of accumulated depreciation and should not be taken as establishing a precedent regarding the return of a more typical accumulated depreciation variance caused by changes in life or salvage estimates. The decisions surrounding the change to the CDNS methodology resulted in a specific set of circumstances under which it is appropriate to deal with the variance in a way that is not typical.

The recommended five-year period was made in consultation with Enbridge to ensure that rate shock was avoided both for current customers and customers in the future. Trueing up the variance over any shorter period would result in significant rate shock upon the completion of the required adjustment period. However extending the return period would result in significant inter-generational inequity to current customers

Gannett Fleming has developed a series of adjustments to ensure refund approximately $292.8 million of accumulated depreciation over a five-year period. In developing the required annual adjustments, Gannett Fleming consulted with Enbridge to develop a declining amount of adjustment per year. In developing this declining annual adjustment, Gannett Fleming specifically considered the amount of true-up already embedded within the depreciation rates presented in Schedule 1. Gannett Fleming considers that the following schedule of annual adjustments are appropriate in the specific circumstances related to this change in net salvage method:

- Refund in 2014 - $74.7 million (25.5% of total)
- Refund in 2015 - $69.7 million (23.8% of total)
- Refund in 2016 - $64.7 million (22.1% of total)
- Refund in 2017 – $59.7 million (20.4% of total)
- Refund in 2018 - <u>$24.0 million</u> (8.2% of total)

Total $292.8 million

As previously noted the depreciation rates as summarized in Schedule 1 include a remaining life calculation whereby the required future accruals, including the net salvage percentage calculated in accordance with the CDNS approach is recovered over the composite remaining life of each account. Included in this calculation is a true-up provision whereby variances between the actual accumulated depreciation balances as at December 31, 2010 and the theoretical accumulated depreciation balance would be adjusted over the remaining life of the assets, including changes caused by the use of the CDNS approach. Gannett Fleming has determined that the depreciation rates provided in Schedule 1 already include an annual amount of $6,617,118 of true up provision related specifically to the conversion to CDNS. Therefore the $6,617,118 needs to be removed from the annual amounts making up the $292.8 refund over the next five years. As such, the amount of additional adjustment in addition to the amounts already provided for in the Schedule 1 depreciation rates are as follows:

- Additional Adjustment in 2014 - $68.1 million
- Additional Adjustment in 2015 - $63.1 million
- Additional Adjustment in 2016 - $58.1 million
- Additional Adjustment in 2017 – $53.1 million
- Additional Adjustment in 2018 – $17.4 million

Total $259.8 million

A summary of the calculations supporting the annual additional adjustment is provided for each year from 2014 through 2018 as shown in Schedules 2A through 2E. Gannett Fleming views that the proposed additional adjustment amounts are appropriate and will result in the least amount of rate shock and inter-generational inequity.

ENBRIDGE GAS DISTRIBUTION, INC.

SCHEDULE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2010
LIFE AND NET SALVAGE WITH REVISED CDNS METHOD

	DEPRECIABLE GROUP	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AS OF DECEMBER 31, 2010	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	UNDERGROUND STORAGE PLANT									
451.10	LAND RIGHTS INTANGIBLE		65-R4	0	40,677,681	20,903,515	19,774,166	471,763	1.16	41.9
452.00	STRUCTURES AND IMPROVEMENTS		45-R1.5	0	14,347,231	4,707,662	9,639,569	264,121	1.84	36.5
453.00	WELLS		45-R3	(7)	39,390,933	18,686,577	23,461,721	611,908	1.55	38.3
454.00	WELL EQUIPMENT		25-R4	0	9,082,877	4,537,985	4,544,893	504,759	5.56	9
455.00	FIELD LINES		55-R3	(8)	46,727,710	20,777,099	29,688,828	722,610	1.55	41.1
456.00	COMPRESSOR EQUIPMENT		40-R2	(8)	91,781,489	31,054,880	68,069,128	2,464,549	2.69	27.6
457.00	MEASURING AND REGULATING EQUIPMENT		30-R1.5	(7)	11,556,320	5,020,691	7,344,571	351,496	3.04	20.9
	TOTAL UNDERGROUND STORAGE PLANT				**253,564,240**	**105,688,408**	**162,522,876**	**5,391,206**		
	DISTRIBUTION PLANT									
471.00	LAND RIGHTS		75-R4	0	7,446,766	1,077,659	6,369,108	87,835	1.18	72.5
472.00	STRUCTURES AND IMPROVEMENTS									
	VICTORIA PARK CENTRE	2018	60-S1.5	20	40,266,238	572,119	29,203,250	3,696,664	9.93	7.9
	KENNEDY ROAD	2013	60-S1.5	20	2,255,051	219,325	1,584,716	530,544	23.53	3.0
	OTTAWA OFFICE	2025	60-S1.5	20	14,185,521	1,519,771	9,828,646	681,838	4.81	14.4
	BROCKVILLE	2025	60-S1.5	20	499,805	42,438	357,406	24,458	4.89	14.6
	ARNPRIOR	2025	60-S1.5	20	570,721	102,517	354,060	25,203	4.42	14.1
	THOROLD OFFICE	2030	60-S1.5	20	11,942,503	1,373,703	8,180,300	430,567	3.61	19.0
	EASTERN	2020	60-S1.5	20	1,598,370	212,254	1,066,442	109,685	6.86	9.7
	KELFIELD	2020	60-S1.5	20	1,198,780	68,117	890,907	90,368	7.54	9.9
	OTTAWA DEPOT	2020	60-S1.5	20	3,071,474	313,477	2,143,702	217,403	7.08	9.9
	OTHER		43-R1	(5)	6,399,993	835,027	9,084,344	281,363	2.98	32.3
	TOTAL STRUCTURES AND IMROVEMENTS				**81,988,456**	**5,258,748**	**62,693,773**	**6,088,093**		10.3
473.00	SERVICES		45-L1.5	(28)	2,024,545,899	869,945,320	1,721,473,431	49,670,133	2.45	34.7
475.10	MAINS - CAST IRON	2016	43-R2	(163)	5,475,959	(9,973,664)	24,375,437	5,492,809	100.31	4.4
475.20	MAINS - BARE STEEL	2016	40-R0.5	(115)	9,114,623	9,031,401	11,476,500	1,948,811	21.38	5.4
475.21	MAINS - COATED STEEL		61-R3	(65)	1,013,837,310	464,144,414	1,208,687,148	28,436,781	2.8	42.5
475.30	MAINS - PLASTIC		65-R3	(55)	1,329,234,200	463,148,188	1,597,164,822	28,878,419	2.17	55.3
475.EN	MAINS - ENVISION		25-SQ	0	123,554,753	19,041,660	104,513,093	4,978,220	4.03	20.99
476.00	COMPANY NGV COMPRESSOR STATIONS		16-R3	0	2,593,466	1,605,736	987,730	154,719	5.97	6.4
477.00	MEASURING AND REGULATING EQUIPMENT		33-L1.5	(7)	314,899,807	159,007,375	168,488,425	6,603,881	2.1	25.5
478.00	METERS		15-S2.5	5	367,745,144	92,616,048	256,741,838	33,901,782	9.22	7.6
	TOTAL DISTRIBUTION PLANT				**5,280,436,383**	**2,074,902,884**	**5,162,971,305**	**166,241,483**		
	GENERAL PLANT									
483.01	OFFICE EQUIPMENT		15-SQ	0	2,943,775	2,894,801	48,973	4,476	0.15	10.9
483.02	FURNISHINGS		20-SQ	0	15,187,994	6,067,053	9,120,940	1,631,823	10.74	5.6
484.00	TRANSPORTATOIN EQUIPMENT		11-R0.5	0	40,957,196	7,841,000	33,116,196	4,324,076	10.56	7.7
484.01	TRANSPORTATION - COMPANY NGV KITS		9-L1	0	7,725,286	4,607,319	3,117,967	695,264	9	4.5
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS		7-S2.5	0	832,469	787,083	45,386	17,454	2.1	2.6
485.00	HEAVY WORK EQUIPMENT		15-L2	25	19,287,539	6,829,160	7,636,495	691,216	3.58	11.0
486.00	TOOLS AND WORK EQUIPMENT		25-SQ	0	34,254,317	13,117,640	21,136,677	1,398,995	4.08	15.1
487.70	RENTAL - VRA'S		20-SQ	0	1,016,149	964,239	51,910	7,519	0.74	6.9
487.80	RENTAL - NGV STATION		20-SQ	0	4,855,654	3,100,277	1,755,377	388,899	8.01	4.5
487.90	RENTAL - NGV CYLINDERS		10-S2.5	0	1,452,290	705,489	746,801	274,905	18.93	2.7
488.00	COMMUNICATION EQUIPMENT		10-SQ	0	3,013,445	2,122,651	890,794	292,699	9.71	3.0
	TOTAL GENERAL PLANT				**131,526,113**	**49,036,712**	**77,667,516**	**9,727,326**		
	COMPUTER AND SOFTWARE									
490.00	COMPUTER EQUIPMENT		5-SQ	0	32,547,213	4,351,484	28,195,729	11,923,129	36.63	2.4
491.01	SOFTWARE - ACQUIRED		4-SQ	0	49,671,020	24,804,515	24,866,505	13,073,699	26.32	1.9
491.02	SOFTWARE - DEVELOPED		5-SQ	0	40,552,311	19,179,561	21,372,750	8,612,322	21.24	2.5
491.03	CIS SOFTWARE ACQUIRED		10-SQ	0	127,098,143	15,741,236	111,356,908	12,709,800 *	10.00	8.5
	TOTAL COMPUTER AND SOFTWARE				**249,868,687**	**64,076,795**	**185,791,892**	**46,318,950**		
	TOTAL DEPRECIABLE GAS PLANT				**5,915,395,423**	**2,293,704,799**	**5,588,953,589**	**227,678,965**		

* Annual Accrual Amount represents amortization for 10 years from previous order
** Annual Accrual Rates for New Structures in Account 472.00 after January 1, 2011 are as follows:

New Kennedy Road	2.13%
Markam TT Building	2.18%
New Fleet Garage	2.13%

Indicates accounts impacted by the recommnedations of this report

ENBRIDGE GAS DISTRIBUTION

SCHEDULE 2A - CALCULATION OF REQUIRED ADDITIONAL TRUE-UP CAUSED BY THE CHANGE IN NET SALVAGE METHODOLOGY (CDNS)

2014

PERCENTAGE TO RETURN: 25.5%

	DEPRECIABLE GROUP	BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	AMOUNT TO TRUE-UP	TRUE-UP INCLUDED IN TABLE 1	ADDITIONAL ADJUSTMENT 2014
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)	(8)
	UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		-		-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		-		-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	(51,194)	(5,242)	(45,952)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		-	-	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	(108,700)	(10,372)	(98,328)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	(218,243)	(31,009)	(187,234)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	(19,268)	(3,615)	(15,652)
	TOTAL UNDERGROUND STORAGE PLANT	**105,688,408**	**85,668,829**	**20,019,579**	**(1,558,450)**	**(397,405)**	**(50,238)**	**(347,167)**
	DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		-		-
472.00	STRUCTURES AND IMPROVEMENTS			-		-		-
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		-		-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		-		-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		-		-
	BROCKVILLE	42,438	138,100	(95,662)		-		-
	ARNPRIOR	102,517	257,902	(155,385)		-		-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		-		-
	EASTERN	212,254	737,401	(525,147)		-		-
	KELFIELD	68,117	370,163	(302,046)		-		-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		-		-
	OTHER	835,027	1,966,614	(1,131,587)		-		-
	TOTAL STRUCTURES AND IMROVEMENTS	5,258,748	32,499,188	(27,240,440)	-	-	-	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	28,075,888	3,172,955	24,902,934
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	(447,714)	(399,032)	(48,682)
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	156,023	113,306	42,716
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	19,092,851	1,761,739	17,331,112
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	27,969,607	1,983,449	25,986,158
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		-	-	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		-	-	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	227,193	34,939	192,253
478.00	METERS	92,616,048	166,232,283	(73,616,235)		-		-
	TOTAL DISTRIBUTION PLANT	**2,074,902,884**	**1,806,934,873**	**267,968,011**	**294,407,247**	**75,073,848**	**6,667,356**	**68,406,492**
								-
	GENERAL PLANT							
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		-		-
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		-		-
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		-		-
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		-		-
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		-		-
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		-		-
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		-		-
487.70	RENTAL - VRA'S	964,239	837,157	127,082		-		-
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		-		-
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		-		-
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		-		-
	TOTAL GENERAL PLANT	**49,036,712**	**53,089,331**	**(4,052,619)**	-	-	-	-
	COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		-		-
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		-		-
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		-		-
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		-		-
	TOTAL COMPUTER AND SOFTWARE	**64,076,795**	**86,414,355**	**(22,337,560)**	-	-	-	-
		2,293,704,799	**2,032,107,388**	**261,597,411**	**292,848,797**	**74,676,443**	**6,617,118**	**68,059,325**

ENBRIDGE GAS DISTRIBUTION

SCHEDULE 2B - CALCULATION OF REQUIRED ADDITIONAL TRUE-UP CAUSED BY THE CHANGE IN NET SALVAGE METHODOLOGY (CDNS)

2015

PERCENTAGE TO RETURN: 23.8%

	DEPRECIABLE GROUP	BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	AMOUNT TO TRUE-UP	TRUE UP INCLUDED IN TABLE 1	ADDITIONAL ADJUSTMENT 2015
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)	(8)
	UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		-		-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		-		-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	(47,781)	(5,242)	(42,539)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		-	-	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	(101,453)	(10,372)	(91,082)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	(203,693)	(31,009)	(172,684)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	(17,983)	(3,615)	(14,368)
	TOTAL UNDERGROUND STORAGE PLANT	**105,688,408**	**85,668,829**	**20,019,579**	**(1,558,450)**	**(370,911)**	**(50,238)**	**(320,673)**
	DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		-		-
472.00	STRUCTURES AND IMPROVEMENTS			-		-		-
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		-		-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		-		-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		-		-
	BROCKVILLE	42,438	138,100	(95,662)		-		-
	ARNPRIOR	102,517	257,902	(155,385)		-		-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		-		-
	EASTERN	212,254	737,401	(525,147)		-		-
	KELFIELD	68,117	370,163	(302,046)		-		-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		-		-
	OTHER	835,027	1,966,614	(1,131,587)		-		-
	TOTAL STRUCTURES AND IMROVEMENTS	5,258,748	32,499,188	(27,240,440)	-	-	-	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	26,204,162	3,172,955	23,031,208
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	(417,866)	(399,032)	(18,834)
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	145,621	113,306	32,315
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	17,819,995	1,761,739	16,058,255
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	26,104,967	1,983,449	24,121,518
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		-	-	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		-	-	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	212,046	34,939	177,107
478.00	METERS	92,616,048	166,232,283	(73,616,235)		-		-
	TOTAL DISTRIBUTION PLANT	**2,074,902,884**	**1,806,934,873**	**267,968,011**	**294,407,247**	**70,068,925**	**6,667,356**	**63,401,568**
								-
	GENERAL PLANT							-
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		-		-
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		-		-
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		-		-
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		-		-
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		-		-
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		-		-
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		-		-
487.70	RENTAL - VRA'S	964,239	837,157	127,082		-		-
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		-		-
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		-		-
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		-		-
	TOTAL GENERAL PLANT	**49,036,712**	**53,089,331**	**(4,052,619)**	-	-	-	-
	COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		-		-
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		-		-
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		-		-
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		-		-
	TOTAL COMPUTER AND SOFTWARE	**64,076,795**	**86,414,355**	**(22,337,560)**	-	-	-	-
		2,293,704,799	**2,032,107,388**	**261,597,411**	**292,848,797**	**69,698,014**	**6,617,118**	**63,080,895**

ENBRIDGE GAS DISTRIBUTION

SCHEDULE 2C - CALCULATION OF REQUIRED ADDITIONAL TRUE-UP CAUSED

2016

PERCENTAGE TO RETURN: 22.1%

	DEPRECIABLE GROUP	BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	AMOUNT TO TRUE-UP	TRUE UP INCLUDED IN TABLE 1	ADDITIONAL ADJUSTMENT 2016
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)	(8)
	UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		-		-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		-		-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	(44,368)	(5,242)	(39,126)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		-	-	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	(94,207)	(10,372)	(83,835)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	(189,144)	(31,009)	(158,135)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	(16,699)	(3,615)	(13,083)
	TOTAL UNDERGROUND STORAGE PLANT	**105,688,408**	**85,668,829**	**20,019,579**	**(1,558,450)**	**(344,417)**	**(50,238)**	**(294,179)**
	DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		-		-
472.00	STRUCTURES AND IMPROVEMENTS			-		-		-
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		-		-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		-		-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		-		-
	BROCKVILLE	42,438	138,100	(95,662)		-		-
	ARNPRIOR	102,517	257,902	(155,385)		-		-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		-		-
	EASTERN	212,254	737,401	(525,147)		-		-
	KELFIELD	68,117	370,163	(302,046)		-		-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		-		-
	OTHER	835,027	1,966,614	(1,131,587)		-		-
	TOTAL STRUCTURES AND IMROVEMENTS	5,258,748	32,499,188	(27,240,440)	-	-	-	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	24,332,436	3,172,955	21,159,482
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	(388,019)	(399,032)	11,013
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	135,220	113,306	21,913
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	16,547,138	1,761,739	14,785,398
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	24,240,326	1,983,449	22,256,877
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		-	-	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		-	-	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	196,900	34,939	161,961
478.00	METERS	92,616,048	166,232,283	(73,616,235)		-		-
	TOTAL DISTRIBUTION PLANT	**2,074,902,884**	**1,806,934,873**	**267,968,011**	**294,407,247**	**65,064,002**	**6,667,356**	**58,396,645**
								-
	GENERAL PLANT							-
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		-		-
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		-		-
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		-		-
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		-		-
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		-		-
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		-		-
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		-		-
487.70	RENTAL - VRA'S	964,239	837,157	127,082		-		-
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		-		-
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		-		-
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		-		-
	TOTAL GENERAL PLANT	**49,036,712**	**53,089,331**	**(4,052,619)**	-	-	-	-
	COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		-		-
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		-		-
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		-		-
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		-		-
	TOTAL COMPUTER AND SOFTWARE	**64,076,795**	**86,414,355**	**(22,337,560)**	-	-	-	-
		2,293,704,799	**2,032,107,388**	**261,597,411**	**292,848,797**	**64,719,584**	**6,617,118**	**58,102,466**

ENBRIDGE GAS DISTRIBUTION

SCHEDULE 2D - CALCULATION OF REQUIRED ADDITIONAL TRUE-UP CAUSED BY THE CHANGE IN NET SALVAGE METHODOLOGY (CDNS)

2017

PERCENTAGE TO RETURN: 20.4%

	DEPRECIABLE GROUP	BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	AMOUNT TO TRUE-UP	TRUE UP INCLUDED IN TABLE 1	ADDITIONAL ADJUSTMENT 2017
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)	(8)
	UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		-		-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		-		-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	(40,955)	(5,242)	(35,713)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		-	-	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	(86,960)	(10,372)	(76,588)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	(174,594)	(31,009)	(143,585)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	(15,414)	(3,615)	(11,799)
	TOTAL UNDERGROUND STORAGE PLANT	**105,688,408**	**85,668,829**	**20,019,579**	**(1,558,450)**	**(317,924)**	**(50,238)**	**(267,686)**
	DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		-		-
472.00	STRUCTURES AND IMPROVEMENTS			-		-		-
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		-		-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		-		-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		-		-
	BROCKVILLE	42,438	138,100	(95,662)		-		-
	ARNPRIOR	102,517	257,902	(155,385)		-		-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		-		-
	EASTERN	212,254	737,401	(525,147)		-		-
	KELFIELD	68,117	370,163	(302,046)		-		-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		-		-
	OTHER	835,027	1,966,614	(1,131,587)		-		-
	TOTAL STRUCTURES AND IMROVEMENTS	5,258,748	32,499,188	(27,240,440)	-	-	-	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	22,460,710	3,172,955	19,287,756
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	(358,171)	(399,032)	40,861
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	124,818	113,306	11,512
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	15,274,281	1,761,739	13,512,542
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	22,375,686	1,983,449	20,392,237
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		-	-	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		-	-	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	181,754	34,939	146,815
478.00	METERS	92,616,048	166,232,283	(73,616,235)		-		-
	TOTAL DISTRIBUTION PLANT	**2,074,902,884**	**1,806,934,873**	**267,968,011**	**294,407,247**	**60,059,078**	**6,667,356**	**53,391,722**
								-
	GENERAL PLANT							-
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		-		-
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		-		-
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		-		-
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		-		-
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		-		-
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		-		-
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		-		-
487.70	RENTAL - VRA'S	964,239	837,157	127,082		-		-
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		-		-
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		-		-
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		-		-
	TOTAL GENERAL PLANT	**49,036,712**	**53,089,331**	**(4,052,619)**	-	-	-	-
	COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		-		-
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		-		-
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		-		-
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		-		-
	TOTAL COMPUTER AND SOFTWARE	**64,076,795**	**86,414,355**	**(22,337,560)**	-	-	-	-
		2,293,704,799	**2,032,107,388**	**261,597,411**	**292,848,797**	**59,741,155**	**6,617,118**	**53,124,036**

ENBRIDGE GAS DISTRIBUTION

SCHEDULE 2E - CALCULATION OF REQUIRED ADDITIONAL TRUE-UP CAUSED
2018

PERCENTAGE TO RETURN: 8.2%

	DEPRECIABLE GROUP	BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	AMOUNT TO TRUE-UP	TRUE UP INCLUDED IN TABLE 1	ADDITIONAL ADJUSTMENT 2018
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)	(8)
	UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		-		-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		-		-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	(16,462)	(5,242)	(11,221)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		-	-	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	(34,955)	(10,372)	(24,583)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	(70,180)	(31,009)	(39,171)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	(6,196)	(3,615)	(2,581)
	TOTAL UNDERGROUND STORAGE PLANT	**105,688,408**	**85,668,829**	**20,019,579**	**(1,558,450)**	**(127,793)**	**(50,238)**	**(77,555)**
	DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		-		-
472.00	STRUCTURES AND IMPROVEMENTS			-		-		-
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		-		-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		-		-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		-		-
	BROCKVILLE	42,438	138,100	(95,662)		-		-
	ARNPRIOR	102,517	257,902	(155,385)		-		-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		-		-
	EASTERN	212,254	737,401	(525,147)		-		-
	KELFIELD	68,117	370,163	(302,046)		-		-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		-		-
	OTHER	835,027	1,966,614	(1,131,587)		-		-
	TOTAL STRUCTURES AND IMROVEMENTS	5,258,748	32,499,188	(27,240,440)	-	-	-	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	9,028,325	3,172,955	5,855,370
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	(143,971)	(399,032)	255,061
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	50,172	113,306	(63,134)
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	6,139,662	1,761,739	4,377,923
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	8,994,148	1,983,449	7,010,699
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		-	-	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		-	-	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	73,058	34,939	38,119
478.00	METERS	92,616,048	166,232,283	(73,616,235)		-		-
	TOTAL DISTRIBUTION PLANT	**2,074,902,884**	**1,806,934,873**	**267,968,011**	**294,407,247**	**24,141,394**	**6,667,356**	**17,474,038**
								-
	GENERAL PLANT							-
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		-		-
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		-		-
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		-		-
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		-		-
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		-		-
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		-		-
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		-		-
487.70	RENTAL - VRA'S	964,239	837,157	127,082		-		-
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		-		-
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		-		-
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		-		-
	TOTAL GENERAL PLANT	**49,036,712**	**53,089,331**	**(4,052,619)**	-	-	-	-
	COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		-		-
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		-		-
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		-		-
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		-		-
	TOTAL COMPUTER AND SOFTWARE	**64,076,795**	**86,414,355**	**(22,337,560)**	-	-	-	-
		2,293,704,799	**2,032,107,388**	**261,597,411**	**292,848,797**	**24,013,601**	**6,617,118**	**17,396,483**

APPENDIX 1

ENBRIDGE GAS DISTRIBUTION

SUMMARY OF FINDINGS BASED ON
PHASE 1 REVIEW OF FUTURE COST OF REMOVAL REQUIREMENTS

Scope of Work Completed

- Review of the Enbridge Gas Distribution (EGD) Asset plan;
- Review of EGD responses to a detailed questionnaire regarding installed pipe types and cost of removal costs and processes;
- Comparison of cost of removal percentages and assumptions to peer companies; and
- Investigation of alternatives (as compared to the traditional method of costs of removal that we used in the study) methods of cost of removal estimation and collection that may be appropriate.

High Level Summary of Findings

Mains

- Approximately 36% of the mains currently in service are coated steel (most of which is a PVC coating):
    - o Approximately 50% of the steel mains currently in service were installed between 1960 and 1980; however as percentage of original cost of coated steel mains this represents less than 20% of the invested cost in coated steel mains.
    - o Over 50% of the original cost still in service relates to less than 20% of the physical pipe in the ground installed after 1990.
- Approximately 64% of mains currently in service are plastic with most (90%) installed after 1980:
    - o 54% of the investment currently in service has been installed since 2000, relating to 35% of the physical installed pipe.
    - o Approximately 79% of the pipe has been installed after 1984, which is a critical date given the chance in use of AMP for the service line connections.
- Distribution mains are only physically removed on rare occasion – usually for highway or Department of Transportation requests. This historic trend is not expected to change in the future. Future abandonment and removal procedures are not expected to materially change from the historic practices and procedures.
- Current cost of abandonment of Mains ranges from $18 to $36 per meter. Given the over 13,000 km of steel mains and the over 22,000 km of plastic mains, the current cost estimates result in funding requirements of over $700 Million (in 2010 dollars). The estimated remaining life of the mains accounts is over 40 years. Assuming a 2% inflation rate per year the required recovery related to the current investment is approximately $1.5 billion.

- The current net salvage percentages would collect approximately $2 billion in total over the life of the assets for the coat steel and plastic mains accounts.
- The net salvage percentages of the peer group used in the 2011 depreciation study ranged from -20% to -75% for both Coated Steel and Plastic Distribution Mains as compared to the -90% (Coated Steel) and -85% (Plastic) as applied for by EGD .

Services

- Over 90% of services currently are plastic pipe, virtually all of which is certified.
- Approximately 80% of the plastic services were installed after 1984, and did not use AMP fittings. These installations comprise over 88% of the investment in services as at December 31, 2010.
- Plastic services installed prior to 1984 (which included the use of AMP fittings) may be subjected to a future replacement program.
- Current cost of abandonment of services averages about $1,100/Service. Given the over estimated 1,976,087 Services, the current cost estimates result in funding requirements of over $2.2 Billion (in 2010 dollars). The estimated remaining life of the mains accounts is approximately 30 years. Assuming a 2% inflation rate per year the required recovery related to the current investment is approximately $4.0 Billion.
- The above estimates are greatly impacted by large cost estimates ($2,000 to $5,000 per Service) relating to approximately 30% of the Services.
- The current net salvage percentages would collect approximately $1 billion in total over the life of the services.
- EGD currently records all contributions related to Service relocations as a credit to the cost of the new service line and none to the accumulated depreciation as Salvage proceeds relating to the abandonment of the old line.
- The net salvage percentages of the peer group used in the 2011 depreciation study ranged from -50% to -100% for both Coated Steel and Plastic Distribution Services, as compared to the -45% as applied for by EGD.

Conclusions and Recommendations

Mains

- The currently applied for Net Salvage percentages are more negative than the industry peers, and may over-collect the net salvage requirements over the estimated remaining life of the Coated Steel and Plastic Distribution Main Accounts.
- The high inflationary period in the early 1980's may have resulted in a high embedded rate of inflation in the traditional net salvage analysis prepared in the 2011 Depreciation Study.
- Study methods that include a normalization of the costs by vintage could be investigated which may result in a more reasonable estimate of future inflation, and a potential reduction in the net salvage estimate. The normalization methods that could be investigated include:

- Use of a Constant Dollar Net Salvage approach similar to that used by TransAlta Utilities between 1984 and 2004. This approach was approved by the Alberta Regulator during this period, however, was not approved for use after 2004.
  - Development of separate depreciation rate calculations for vintages prior to 1985, in order to isolate the high inflationary period in the early 1980's. This would allow for a lower net salvage rate relating to most of the investment in service for the period of post 1985.
- Given the potential for over-recovery, use of a zero percent (or a very reduced) rate for a short period of time could be considered. However, it is often difficult to re-instate net salvage percentage in future applications, when they again become necessary.

<u>Services</u>

- At this time, the distribution Services account is not high, and in fact may be low considering the current cost estimates for abandonment of services and rates used by industry peers. As such, it is not likely that any further study would result in a reduced reserve for future removal related to this account.

APPENDIX II

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 453.00 - WELLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -7						
1963	236,690.80	208,404	253,259			
1964	328,705.74	286,060	351,715			
1965	34,145.77	29,350	36,536			
1966	293,679.89	249,156	314,237			
1968	183,177.64	151,051	196,000			
1969	417,248.96	338,811	446,456			
1970	53,284.19	42,558	57,014			
1971	381,190.89	299,290	407,874			
1972	230,343.21	177,622	246,467			
1973	112,820.71	85,334	120,718			
1974	252,754.70	187,390	270,448			
1975	67,285.82	48,861	71,996			
1976	56,281.42	39,974	60,221			
1978	436,363.33	295,605	466,909			
1980	104,232.11	67,065	111,528			
1983	704,130.85	415,217	753,420			
1984	256,587.06	146,548	272,171	2,377	20.98	113
1985	196,362.32	108,462	201,437	8,671	21.77	398
1987	2,968,778.19	1,526,162	2,834,413	342,180	23.38	14,636
1988	1,093,441.12	540,532	1,003,885	166,097	24.21	6,861
1989	1,657,305.24	786,572	1,460,834	312,483	25.04	12,479
1990	223,259.49	101,448	188,411	50,477	25.89	1,950
1991	7,070.80	3,070	5,702	1,864	26.74	70
1993	323.42	127	236	110	28.49	4
1994	52,007.28	19,328	35,896	19,752	29.37	673
1996	3,273,351.28	1,076,419	1,999,143	1,503,343	31.17	48,230
1997	3,079,459.11	946,034	1,756,990	1,538,031	32.08	47,944
1998	1,246,567.85	355,692	660,597	673,231	33.00	20,401
1999	3,052,785.28	803,554	1,492,374	1,774,106	33.93	52,287
2000	846,827.05	204,173	379,193	526,912	34.86	15,115
2001	890,530.48	194,595	361,405	591,463	35.81	16,517
2002	927,627.77	181,966	337,950	654,612	36.75	17,813
2003	1,109,439.29	192,310	357,161	829,939	37.71	22,008
2004	452,253.93	68,072	126,425	357,487	38.67	9,245
2005	1,366,690.63	174,503	324,090	1,138,269	39.63	28,722
2006	996,980.51	104,309	193,724	873,045	40.60	21,504
2007	727,143.68	59,302	110,137	667,907	41.57	16,067
2008	1,181,974.42	68,851	127,871	1,136,842	42.55	26,718
2009	1,794,438.60	62,728	116,500	1,803,549	43.53	41,432
2010	8,097,391.77	94,353	175,234	8,488,976	44.51	190,721
	39,390,932.60	10,740,858	18,686,577	23,461,721		611,908

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.3   1.55

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 455.00 - FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -8						
1963	2,630,971.32	2,061,329	2,790,884	50,565	15.10	3,349
1964	14,882.07	11,482	15,546	527	15.71	34
1965	20,038.98	15,220	20,607	1,035	16.32	63
1966	68,742.85	51,349	69,523	4,719	16.96	278
1967	40,165.52	29,490	39,927	3,452	17.61	196
1968	112,031.80	80,802	109,400	11,594	18.27	635
1969	63,074.63	44,663	60,470	7,651	18.94	404
1970	52,764.41	36,647	49,617	7,369	19.63	375
1971	196,492.13	133,770	181,114	31,098	20.33	1,530
1973	64,589.43	42,146	57,063	12,694	21.77	583
1974	63,696.80	40,650	55,037	13,756	22.50	611
1975	14,919.47	9,302	12,594	3,519	23.25	151
1976	4,509,317.32	2,744,037	3,715,219	1,154,844	24.01	48,098
1977	2,007,172.62	1,191,480	1,613,174	554,572	24.77	22,389
1978	45,035.42	26,043	35,260	13,378	25.55	524
1979	14,026.95	7,894	10,688	4,461	26.34	169
1982	27,744.18	14,295	19,354	10,610	28.76	369
1983	63,775.74	31,822	43,085	25,793	29.59	872
1984	3,369.95	1,627	2,203	1,437	30.42	47
1985	553,892.18	258,209	349,595	248,609	31.26	7,953
1987	5,894,962.87	2,550,126	3,452,678	2,913,882	32.97	88,380
1988	153,102.61	63,615	86,130	79,221	33.84	2,341
1989	115,369.32	45,943	62,203	62,396	34.72	1,797
1994	1,444,423.00	447,854	606,360	953,617	39.21	24,321
1996	542,784.69	148,574	201,158	385,049	41.06	9,378
1997	8,115,463.15	2,073,290	2,807,078	5,957,622	41.99	141,882
1998	1,316,983.06	312,133	422,605	999,737	42.93	23,288
1999	7,039,455.98	1,538,465	2,082,965	5,519,647	43.87	125,818
2000	746,802.38	149,429	202,316	604,231	44.81	13,484
2001	5,749.65	1,042	1,411	4,799	45.77	105
2002	1,048,123.66	170,419	230,734	901,240	46.72	19,290
2003	2,360,715.05	338,864	458,796	2,090,776	47.69	43,841
2004	2,746,444.07	342,443	463,642	2,502,518	48.65	51,439
2005	767,388.02	81,071	109,764	719,015	49.62	14,490
2006	2,064,582.83	178,781	242,056	1,987,693	50.59	39,290
2007	630,307.19	42,450	57,474	623,258	51.57	12,086
2008	2,418.49	117	158	2,454	52.54	47
2009	912,565.59	26,522	35,910	949,661	53.52	17,744
2010	253,364.39	2,438	3,301	270,333	54.51	4,959
	46,727,709.77	15,345,833	20,777,099	29,688,828		722,610

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.1   1.55

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 456.00 - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -8						
1964	3,397,061.10	2,909,379	2,932,426	736,400	8.28	88,937
1969	43,657.29	34,926	35,203	11,947	10.37	1,152
1971	1,966,168.04	1,523,053	1,535,118	588,343	11.31	52,020
1972	6,110.26	4,652	4,689	1,910	11.80	162
1973	3,059,499.98	2,288,200	2,306,326	997,934	12.30	81,133
1974	237,601.26	174,366	175,747	80,862	12.82	6,307
1975	1,983,554.30	1,426,731	1,438,033	704,206	13.36	52,710
1980	534,002.97	342,429	345,142	231,581	16.25	14,251
1981	3,857,456.42	2,409,020	2,428,103	1,737,950	16.87	103,020
1982	4,133,805.64	2,511,287	2,531,181	1,933,329	17.50	110,476
1983	35,604.20	21,005	21,171	17,282	18.15	952
1985	2,969.22	1,645	1,658	1,549	19.48	80
1986	209,951.59	112,467	113,358	113,390	20.16	5,625
1987	25,236.41	13,042	13,145	14,110	20.86	676
1988	1,491,274.81	742,476	748,358	862,219	21.56	39,992
1989	55,142.77	26,383	26,592	32,962	22.28	1,479
1990	959,655.99	440,223	443,710	592,718	23.01	25,759
1991	87,929.97	38,579	38,885	56,079	23.75	2,361
1992	2,748,768.03	1,150,359	1,159,472	1,809,197	24.50	73,845
1994	432,698.55	163,210	164,503	302,811	26.03	11,633
1995	9,545,345.30	3,396,807	3,423,715	6,885,258	26.82	256,721
1996	3,498,227.71	1,170,262	1,179,532	2,598,554	27.61	94,116
1997	11,740,522.61	3,673,962	3,703,066	8,976,698	28.41	315,970
1998	1,280,742.17	373,119	376,075	1,007,127	29.21	34,479
1999	3,574,340.71	962,177	969,799	2,890,489	30.03	96,253
2000	5,401,223.85	1,332,914	1,343,473	4,489,849	30.86	145,491
2001	1,471,061.66	330,062	332,677	1,256,070	31.69	39,636
2002	2,402,256.44	483,862	487,695	2,106,742	32.54	64,743
2003	3,801,525.34	678,458	683,833	3,421,814	33.39	102,480
2004	3,345,012.29	520,216	524,337	3,088,276	34.24	90,195
2005	3,257,105.37	430,036	433,442	3,084,232	35.11	87,845
2006	5,244,506.04	569,239	573,748	5,090,319	35.98	141,476
2007	1,469,779.73	124,211	125,195	1,462,167	36.87	39,657
2008	3,924,021.31	238,384	240,273	3,997,670	37.75	105,899
2009	4,690,963.97	170,986	172,340	4,893,901	38.65	126,621
2010	1,866,705.50	22,680	22,860	1,993,182	39.55	50,397
	91,781,488.80	30,810,807	31,054,880	68,069,128		2,464,549

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.6   2.69

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 457.00 - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R1.5						
NET SALVAGE PERCENT.. -7						
1963	130,385.00	122,864	139,512			
1964	4,669.71	4,357	4,997			
1971	29,834.21	25,623	31,913	10	5.92	2
1972	2.00	2	2			
1975	230,863.23	186,750	232,592	14,432	7.32	1,972
1977	55,685.42	43,476	54,148	5,435	8.11	670
1979	19,235.52	14,435	17,978	2,604	8.96	291
1984	99,162.31	65,819	81,976	24,128	11.39	2,118
1987	645,515.34	390,018	485,757	204,944	13.06	15,692
1988	62,394.01	36,385	45,317	21,445	13.65	1,571
1989	93,552.32	52,553	65,453	34,648	14.25	2,431
1993	39,247.64	18,464	22,996	18,999	16.81	1,130
1994	446,474.29	199,212	248,113	229,614	17.49	13,128
1996	402,201.23	159,662	198,855	231,500	18.87	12,268
1997	1,866,454.66	693,655	863,929	1,133,177	19.58	57,874
2000	6,340,252.61	1,863,381	2,320,792	4,463,278	21.76	205,114
2001	13,458.94	3,596	4,479	9,922	22.51	441
2002	1,039.05	250	311	801	23.26	34
2003	595,307.24	126,759	157,875	479,104	24.03	19,938
2005	63,577.47	10,023	12,483	55,545	25.58	2,171
2006	36,592.08	4,750	5,916	33,238	26.36	1,261
2007	38,359.14	3,886	4,840	36,204	27.16	1,333
2008	196,488.02	14,296	17,806	192,436	27.96	6,883
2010	145,568.22	2,129	2,651	153,107	29.59	5,174
	11,556,319.66	4,042,345	5,020,691	7,344,571		351,496

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.9   3.04

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 473.00 - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-L1.5						
NET SALVAGE PERCENT.. -28						
1954	1,375,060.32	1,122,542	1,521,715	238,362	16.30	14,623
1955	390,704.82	316,065	428,457	71,645	16.56	4,326
1956	824,390.15	660,799	895,777	159,442	16.82	9,479
1957	1,557,351.14	1,236,791	1,676,590	316,819	17.08	18,549
1958	1,664,865.89	1,309,879	1,775,668	355,360	17.34	20,494
1959	1,097,949.78	855,719	1,160,010	245,366	17.60	13,941
1960	1,469,527.14	1,134,447	1,537,853	343,142	17.86	19,213
1961	2,305,539.11	1,762,125	2,388,731	562,359	18.13	31,018
1962	3,321,611.71	2,514,136	3,408,155	843,508	18.39	45,868
1963	2,709,710.89	2,030,974	2,753,182	715,248	18.65	38,351
1964	1,188,962.42	882,016	1,195,658	326,214	18.92	17,242
1965	1,978,747.27	1,452,711	1,969,291	563,506	19.19	29,365
1966	2,796,471.96	2,032,359	2,755,060	824,424	19.45	42,387
1967	3,368,292.36	2,422,066	3,283,345	1,028,069	19.72	52,133
1968	4,790,118.17	3,406,334	4,617,616	1,513,735	20.00	75,687
1969	4,907,017.24	3,451,777	4,679,219	1,601,763	20.27	79,021
1970	4,197,486.34	2,919,194	3,957,251	1,415,532	20.55	68,882
1971	7,140,091.45	4,906,808	6,651,654	2,487,663	20.84	119,370
1972	7,326,937.96	4,974,721	6,743,717	2,634,764	21.13	124,693
1973	10,953,607.38	7,346,804	9,959,306	4,061,311	21.42	189,604
1974	8,143,263.28	5,390,032	7,306,711	3,116,666	21.73	143,427
1975	9,661,451.52	6,309,716	8,553,432	3,813,226	22.04	173,014
1976	9,972,568.61	6,422,143	8,705,838	4,059,050	22.36	181,532
1977	11,002,607.67	6,982,237	9,465,100	4,618,238	22.69	203,536
1978	13,646,154.83	8,527,777	11,560,229	5,906,849	23.03	256,485
1979	22,162,057.48	13,628,850	18,475,228	9,892,206	23.38	423,105
1980	23,589,254.20	14,258,327	19,328,546	10,865,699	23.75	457,503
1981	25,067,158.83	14,873,769	20,162,837	11,923,126	24.14	493,916
1982	20,292,768.89	11,809,937	16,009,515	9,965,229	24.54	406,081
1983	23,349,772.82	13,316,768	18,052,171	11,835,538	24.95	474,370
1984	31,038,230.19	17,313,075	23,469,553	16,259,382	25.39	640,385
1985	25,363,218.24	13,822,913	18,738,300	13,726,619	25.84	531,216
1986	32,195,819.36	17,106,952	23,190,133	18,020,516	26.32	684,670
1987	33,623,958.17	17,387,621	23,570,607	19,468,059	26.82	725,878
1988	37,309,414.63	18,741,385	25,405,766	22,350,285	27.34	817,494
1989	37,040,676.84	18,027,016	24,437,369	22,974,697	27.89	823,761
1990	43,008,724.90	20,221,945	27,412,808	27,638,360	28.47	970,789
1991	48,568,980.04	22,007,576	29,833,404	32,334,890	29.07	1,112,311
1992	60,448,663.62	26,307,258	35,662,040	41,712,249	29.70	1,404,453
1993	65,776,976.52	27,410,371	37,157,417	47,037,113	30.35	1,549,823
1994	77,904,278.04	30,956,293	41,964,258	57,753,218	31.03	1,861,206
1995	83,485,978.05	31,512,550	42,718,319	64,143,733	31.73	2,021,548
1996	87,516,145.33	31,241,444	42,350,808	69,669,858	32.45	2,146,991
1997	64,415,823.19	21,638,769	29,333,451	53,118,803	33.19	1,600,446

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 473.00 - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-L1.5						
NET SALVAGE PERCENT.. -28						
1998	74,799,406.06	23,510,710	31,871,048	63,872,192	33.95	1,881,361
1999	86,638,135.41	25,333,268	34,341,703	76,555,110	34.72	2,204,928
2000	103,836,807.85	28,000,384	37,957,237	94,953,877	35.52	2,673,251
2001	88,791,584.70	21,871,427	29,648,841	84,004,387	36.34	2,311,623
2002	71,333,322.82	15,867,270	21,509,624	69,797,029	37.18	1,877,274
2003	91,572,174.00	18,129,239	24,575,942	92,636,441	38.04	2,435,238
2004	32,408,883.32	5,604,818	7,597,875	33,885,496	38.92	870,645
2005	76,785,648.18	11,335,282	15,366,075	82,919,555	39.81	2,082,883
2006	88,514,405.34	10,775,815	14,607,663	98,690,776	40.72	2,423,644
2007	89,078,390.52	8,487,674	11,505,865	102,514,475	41.65	2,461,332
2008	85,369,079.63	5,827,498	7,899,739	101,372,683	42.60	2,379,640
2009	95,267,455.47	3,928,982	5,326,116	116,616,227	43.55	2,677,755
2010	80,202,216.60	1,117,955	1,515,497	101,143,341	44.51	2,272,373
	2,024,545,898.65	641,743,313	869,945,320	1,721,473,431		49,670,133

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.7   2.45

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.20 - MAINS - BARE STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 40-R0.5						
PROBABLE RETIREMENT YEAR.. 12-2016						
NET SALVAGE PERCENT.. -115						
1954	3,998,454.09	7,492,949	5,144,248	3,452,428	4.97	694,654
1956	1,027,729.08	1,918,567	1,317,183	892,435	5.05	176,720
1958	302,918.18	563,339	386,758	264,516	5.12	51,663
1967	50,478.75	92,014	63,172	45,357	5.37	8,446
1983	3,159.72	5,395	3,704	3,089	5.65	547
2005	113,491.85	113,571	77,972	166,035	5.80	28,627
2006	1,431,562.45	1,282,452	880,461	2,197,398	5.81	378,210
2007	2,186,793.24	1,686,560	1,157,899	3,543,706	5.81	609,932
2010	35.33	6	4	72	5.82	12
	9,114,622.69	13,154,853	9,031,401	10,565,038		1,948,811

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4   21.38

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.10 - MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 43-R2						
PROBABLE RETIREMENT YEAR.. 12-2016						
NET SALVAGE PERCENT.. -163						
1954	4,812,965.10	11,369,124	8,864,745-	21,522,843	4.33	4,970,633
1956	98,858.71	232,454	181,249-	441,247	4.48	98,493
1958	1,339.80	3,136	2,445-	5,969	4.62	1,292
1982	22,762.08	48,982	38,192-	98,056	5.67	17,294
1983	523,645.96	1,119,930	873,234-	2,250,423	5.69	395,505
2002	946.13	1,450	1,131-	3,619	5.91	612
2005	12,524.24	15,653	12,205-	45,144	5.93	7,613
2010	2,917.15	595	463-	8,136	5.95	1,367
	5,475,959.17	12,791,324	9,973,664-	24,375,437		5,492,809

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4   100.31

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.21 - MAINS - COATED STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 61-R3						
NET SALVAGE PERCENT.. -65						
1955	20,682.00	25,661	24,102	10,023	15.13	662
1956	454,363.03	556,869	523,036	226,663	15.69	14,446
1957	1,521,812.04	1,841,259	1,729,392	781,598	16.27	48,039
1958	2,087,151.76	2,491,968	2,340,567	1,103,233	16.86	65,435
1959	33,457,103.89	39,403,117	37,009,152	18,195,069	17.46	1,042,100
1960	8,575,207.68	9,955,443	9,350,593	4,798,500	18.08	265,404
1961	10,276,607.22	11,755,534	11,041,318	5,915,084	18.71	316,146
1962	10,764,673.03	12,124,499	11,387,866	6,373,844	19.36	329,227
1963	12,845,966.69	14,239,369	13,374,246	7,821,599	20.02	390,689
1964	5,600,017.45	6,105,996	5,735,022	3,505,007	20.69	169,406
1965	5,086,518.26	5,452,521	5,121,249	3,271,506	21.37	153,089
1966	9,033,911.08	9,515,364	8,937,251	5,968,702	22.06	270,567
1967	9,373,988.25	9,693,529	9,104,592	6,362,489	22.77	279,424
1968	8,869,262.93	9,001,255	8,454,377	6,179,907	23.48	263,199
1969	10,451,851.66	10,400,967	9,769,049	7,476,506	24.21	308,819
1970	13,668,371.82	13,328,262	12,518,494	10,034,320	24.95	402,177
1971	19,899,826.08	19,006,374	17,851,628	14,983,085	25.69	583,226
1972	13,555,229.49	12,667,952	11,898,301	10,467,828	26.45	395,759
1973	16,858,338.04	15,408,260	14,472,120	13,344,138	27.21	490,413
1974	11,117,110.88	9,926,441	9,323,353	9,019,880	27.99	322,254
1975	6,995,961.48	6,099,037	5,728,485	5,814,851	28.77	202,115
1976	3,633,992.12	3,090,443	2,902,681	3,093,406	29.56	104,648
1977	6,254,391.75	5,183,609	4,868,675	5,451,071	30.36	179,548
1978	5,136,752.41	4,144,758	3,892,940	4,582,701	31.17	147,023
1979	5,783,604.02	4,538,339	4,262,609	5,280,338	31.99	165,062
1980	8,449,567.10	6,442,917	6,051,473	7,890,313	32.81	240,485
1981	7,122,608.49	5,269,263	4,949,125	6,803,179	33.65	202,175
1982	7,352,952.64	5,272,607	4,952,266	7,180,106	34.49	208,179
1983	9,414,993.42	6,534,843	6,137,814	9,396,925	35.34	265,901
1984	5,677,033.82	3,808,291	3,576,915	5,790,191	36.20	159,950
1985	8,800,349.47	5,698,746	5,352,514	9,168,063	37.06	247,384
1986	8,778,770.56	5,478,216	5,145,383	9,339,588	37.93	246,232
1987	25,977,515.20	15,592,237	14,644,919	28,217,981	38.81	727,080
1988	9,604,938.71	5,533,857	5,197,643	10,650,506	39.70	268,275
1989	30,168,371.70	16,655,159	15,643,263	34,134,550	40.59	840,960
1990	31,319,791.98	16,528,582	15,524,376	36,153,281	41.49	871,373
1991	69,704,461.13	35,087,971	32,956,175	82,056,186	42.39	1,935,744
1992	56,418,087.79	26,996,055	25,355,890	67,733,955	43.31	1,563,933
1993	15,236,787.45	6,915,704	6,495,535	18,645,164	44.22	421,645
1994	17,060,135.80	7,314,294	6,869,909	21,279,315	45.15	471,303
1995	15,246,702.81	6,153,165	5,779,325	19,377,735	46.08	420,524
1996	26,244,188.83	9,931,090	9,327,719	33,975,193	47.01	722,723
1997	13,184,751.41	4,654,013	4,371,255	17,383,585	47.95	362,536
1998	24,981,157.67	8,182,778	7,685,627	33,533,283	48.89	685,892

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.21 - MAINS - COATED STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 61-R3						
NET SALVAGE PERCENT.. -65						
1999	28,665,753.99	8,653,259	8,127,524	39,170,970	49.84	785,934
2000	25,252,852.33	6,974,257	6,550,531	35,116,675	50.79	691,409
2001	37,783,177.86	9,453,578	8,879,219	53,463,024	51.75	1,033,102
2002	46,384,439.31	10,401,015	9,769,094	66,765,231	52.71	1,266,652
2003	13,808,186.42	2,734,021	2,567,914	20,215,594	53.68	376,595
2004	16,553,642.72	2,847,707	2,674,692	24,638,818	54.64	450,930
2005	21,576,108.65	3,145,667	2,954,550	32,646,029	55.61	587,053
2006	46,450,757.46	5,541,343	5,204,675	71,439,075	56.59	1,262,398
2007	66,432,543.90	6,181,116	5,805,577	103,808,120	57.56	1,803,477
2008	42,472,101.02	2,826,285	2,654,572	67,424,395	58.54	1,151,766
2009	29,441,111.70	1,178,498	1,106,898	47,470,936	59.52	797,563
2010	16,950,773.41	224,589	210,944	27,757,833	60.51	458,731
	1,013,837,309.81	494,167,949	464,144,414	1,208,687,148		28,436,781

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.5 2.80

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.30 - MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -55						
1970	17,524.99	15,220	21,226	5,938	28.58	208
1971	170,927.02	145,307	202,647	62,290	29.35	2,122
1972	409,522.46	340,523	474,897	159,863	30.13	5,306
1973	2,574,571.18	2,092,902	2,918,782	1,071,803	30.91	34,675
1974	3,816,219.97	3,029,439	4,224,886	1,690,255	31.71	53,304
1975	4,463,691.19	3,458,323	4,823,012	2,095,709	32.51	64,464
1976	5,218,685.51	3,942,399	5,498,110	2,590,853	33.32	77,757
1977	6,195,271.07	4,559,060	6,358,111	3,244,559	34.14	95,037
1978	7,839,559.84	5,615,731	7,831,755	4,319,563	34.96	123,557
1979	12,554,859.33	8,742,030	12,191,723	7,268,309	35.80	203,025
1980	23,453,620.43	15,861,226	22,120,226	14,232,886	36.64	388,452
1981	10,185,896.40	6,682,014	9,318,804	6,469,335	37.49	172,562
1982	14,590,791.67	9,275,840	12,936,180	9,679,547	38.34	252,466
1983	12,927,736.48	7,950,474	11,087,811	8,950,181	39.21	228,263
1984	13,680,605.18	8,129,549	11,337,551	9,867,387	40.08	246,192
1985	11,846,542.77	6,793,992	9,474,970	8,887,171	40.95	217,025
1986	12,763,076.10	7,051,765	9,834,463	9,948,305	41.83	237,827
1987	18,145,068.10	9,640,357	13,444,539	14,680,317	42.72	343,640
1988	16,045,984.92	8,180,660	11,408,831	13,462,446	43.62	308,630
1989	25,078,994.07	12,247,929	17,081,086	21,791,355	44.52	489,473
1990	19,959,571.94	9,314,613	12,990,254	17,947,083	45.43	395,049
1991	24,902,772.66	11,081,086	15,453,795	23,145,503	46.34	499,471
1992	20,301,996.30	8,588,272	11,977,291	19,490,803	47.26	412,416
1993	22,797,943.09	9,144,107	12,752,464	22,584,348	48.18	468,749
1994	25,624,013.06	9,709,272	13,540,649	26,176,571	49.11	533,019
1995	37,105,636.79	13,228,160	18,448,126	39,065,611	50.05	780,532
1996	43,426,407.66	14,508,198	20,233,280	47,077,652	50.99	923,272
1997	39,877,999.15	12,428,936	17,333,520	44,477,379	51.93	856,487
1998	53,459,880.91	15,450,601	21,547,564	61,315,251	52.88	1,159,517
1999	55,871,378.17	14,882,319	20,755,033	65,845,603	53.83	1,223,214
2000	57,340,549.28	13,974,265	19,488,651	69,389,200	54.78	1,266,689
2001	67,933,421.35	15,000,583	20,919,965	84,376,838	55.74	1,513,757
2002	52,389,851.10	10,356,792	14,443,687	66,760,582	56.71	1,177,228
2003	54,090,485.56	9,454,665	13,185,571	70,654,682	57.67	1,225,155
2004	32,743,360.13	4,966,104	6,925,779	43,826,429	58.64	747,381
2005	60,030,865.77	7,715,527	10,760,152	82,287,690	59.61	1,380,434
2006	109,198,893.59	11,484,175	16,015,946	153,242,339	60.59	2,529,169
2007	106,733,135.48	8,754,892	12,209,661	153,226,699	61.56	2,489,063

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 475.30 - MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -55						
2008	75,188,541.43	4,411,124	6,151,798	110,390,441	62.54	1,765,117
2009	81,485,550.36	2,875,910	4,010,773	122,291,830	63.52	1,925,249
2010	86,792,797.51	1,014,347	1,414,619	133,114,217	64.51	2,063,466
	1,329,234,199.97	332,098,688	463,148,188	1,597,164,822		28,878,419

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 55.3   2.17

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 477.00 - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-L1.5						
NET SALVAGE PERCENT.. -4						
1955	118,200.17	91,042	122,928			
1956	13,063.71	9,971	13,586			
1957	503,196.88	380,441	523,325			
1958	218,728.25	163,852	227,477			
1959	25,693.60	19,053	26,721			
1960	190,377.25	139,794	197,992			
1961	60,592.69	44,035	63,016			
1962	153,425.59	110,341	159,563			
1963	152,060.76	108,208	158,143			
1964	86,856.71	61,124	90,331			
1965	154,693.34	107,644	160,881			
1966	95,012.46	65,367	98,813			
1967	216,244.21	147,067	224,894			
1968	140,527.66	94,421	146,149			
1969	232,628.93	154,397	241,934			
1970	183,146.84	120,114	190,473			
1971	295,728.47	191,525	307,558			
1972	878,274.69	561,607	913,406			
1973	349,398.01	220,448	363,374			
1974	679,123.88	422,919	706,289			
1975	736,842.97	452,824	766,317			
1976	618,854.14	375,050	643,608			
1977	1,072,986.55	641,479	1,105,073	10,833	14.03	772
1978	1,375,922.97	810,882	1,396,903	34,057	14.30	2,382
1979	1,243,907.78	722,486	1,244,624	49,040	14.57	3,366
1980	1,483,393.63	848,501	1,461,709	81,020	14.85	5,456
1981	1,810,654.41	1,019,726	1,756,678	126,403	15.13	8,354
1982	1,719,906.60	952,896	1,641,550	147,153	15.42	9,543
1983	1,756,802.17	957,277	1,649,097	177,977	15.71	11,329
1984	4,359,220.49	2,334,118	4,020,975	512,614	16.01	32,018
1985	3,809,858.44	2,001,532	3,448,031	514,222	16.33	31,489
1986	3,214,931.24	1,655,548	2,852,006	491,522	16.66	29,503
1987	6,280,384.92	3,164,887	5,452,138	1,079,462	17.01	63,460
1988	5,230,266.94	2,576,354	4,438,274	1,001,204	17.37	57,640
1989	6,150,887.33	2,956,146	5,092,540	1,304,383	17.75	73,486
1990	11,156,952.99	5,217,973	8,988,980	2,614,251	18.16	143,957
1991	9,450,239.07	4,291,701	7,393,295	2,434,954	18.59	130,982
1992	6,681,535.03	2,939,549	5,063,949	1,884,847	19.04	98,994
1993	8,954,181.66	3,801,115	6,548,165	2,764,184	19.53	141,535
1994	10,439,797.06	4,260,657	7,339,816	3,517,573	20.05	175,440
1995	11,991,224.85	4,686,056	8,072,649	4,398,225	20.60	213,506
1996	12,750,685.77	4,741,766	8,168,620	5,092,093	21.20	240,193
1997	10,356,057.25	3,648,870	6,285,893	4,484,407	21.82	205,518
1998	14,314,273.29	4,745,777	8,175,530	6,711,314	22.48	298,546

ENBRIDGE GAS DISTRIBUTION, INC.
USING THE CDNS NET SALVAGE PERCENTAGES

ACCOUNT 477.00 - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-L1.5						
NET SALVAGE PERCENT.. -4						
1999	17,504,814.37	5,422,907	9,342,019	8,862,988	23.17	382,520
2000	18,280,431.89	5,248,356	9,041,321	9,970,328	23.89	417,343
2001	9,701,072.14	2,555,876	4,402,997	5,686,118	24.64	230,768
2002	10,459,382.00	2,501,884	4,309,985	6,567,772	25.41	258,472
2003	13,421,103.63	2,871,987	4,947,560	9,010,388	26.21	343,777
2004	17,193,858.86	3,229,598	5,563,615	12,317,998	27.04	455,547
2005	12,493,778.70	2,008,150	3,459,432	9,534,098	27.90	341,724
2006	13,760,480.89	1,830,078	3,152,668	11,158,232	28.78	387,708
2007	15,403,627.34	1,611,749	2,776,553	13,243,219	29.68	446,200
2008	19,364,142.48	1,458,445	2,512,457	17,626,251	30.61	575,833
2009	16,862,292.28	770,566	1,327,451	16,209,333	31.55	513,766
2010	8,748,080.73	132,376	228,044	8,869,960	32.52	272,754
	314,899,806.96	92,658,512	159,007,375	168,488,425		6,603,881

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.5   2.10

SCHEDULE OF DEPRECIATION RATES

Effective January 1, 2014

Account Number	Account Description	Existing Depreciation Rate	Proposed Depreciation Rate
Storage Plant			
451	Land Rights	1.16%	1.16%
452	Structures & Improvements	1.84%	1.84%
453	Wells	1.49%	1.55%
454	Well Equipment	5.56%	5.56%
455	Gathering Lines	1.46%	1.55%
456	Compressor Equipment	2.56%	2.69%
457	Regulating Equipment	2.94%	3.04%
Distribution Plant			
471	Land Rights	1.18%	1.18%
472	Structures & Improvements		
	472 VPC	9.93%	9.93%
	472 Ottawa (Coventry)	4.81%	4.81%
	472 Thorold	3.61%	3.61%
	472 Other	2.98%	2.98%
	472 Ottawa Depot (SMOC)	7.08%	7.08%
	472 Old Kennedy Rd	23.53%	23.53%
	472 Eastern Ave (Stn B)	6.86%	6.86%
	472 Kelfield	7.54%	7.54%
	472 Arnprior	4.42%	4.42%
	472 Brockville	4.89%	4.89%
	472 Tech Training (Markham)	2.18%	2.18%
	472 Casselman/Pembroke	2.98%	2.98%
	472 New Kennedy/Fleet Garage	2.13%	2.13%
473/474	Service/Meter Installations	2.98%	2.45%
475	Mains - Plastic	2.74%	2.17%
	- Coated & Wrapped Steel	3.46%	2.80%
	- Cast Iron	91.75%	100.31%
	- Other	23.27%	21.38%
	- Envision	4.03%	4.03%
476	Company NGV Refueling Stations	5.97%	5.97%
477	Regulating Equipment	2.14%	2.10%
478	Meters	9.22%	9.22%

Witnesses: L. Au
R. Lei

Account Number	Account Description	Existing Depreciation Rate	Proposed Depreciation Rate
General Plant			
482.5	Leasehold Improvements	Amortized over the life of the	Amortized over the life of the lease
483.01	Office Equipment	0.15%	0.15%
483.02	Office Furniture	10.74%	10.74%
484	Transportation Equipment	10.56%	10.56%
484.01	NGV Conversion Kits	9.00%	9.00%
484.02	NGV Cylinders	2.10%	2.10%
485	Heavy Work Equipment	3.58%	3.58%
486	Small Tools and Work Equipment	4.08%	4.08%
487.7	NGV Rental Refueling Appliances	0.74%	0.74%
487.8	NGV Rental Refueling Stations	8.01%	8.01%
487.9	NGV Rental Cylinders	18.93%	18.93%
488	Communications Equipment	9.71%	9.71%
489	Software Applications - CIS	10.00%	10.00%
490	Computer Equipment		
490	IT -Hardware	36.63%	36.63%
490	IT -Software Acquired	26.32%	26.32%
490	IT -Software Developed	21.24%	21.24%

COST OF SERVICE
2014 FISCAL YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,455.9	-	1,455.9
2.	Operation and maintenance	425.3	(92.6)	332.7
3.	Depreciation and amortization expense	262.8	(12.7)	250.1
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	41.2	-	41.2
6.	Operating costs	2,187.1	(105.3)	2,081.8
7.	Income tax expense			25.5
8.	Cost of service			2,107.3

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2014 FISCAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(92.6)	Operation and Maintenance
		To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense
		To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 FISCAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	346.7	346.7	
	Add			
2.	Depreciation and amortization	250.1	250.1	
3.	Accrual based pension and OPEB costs	37.3	37.3	
4.	Other non-deductible items	1.4	1.4	
5.	Total Add Back	288.8	288.8	
6.	Sub-total	635.5	635.5	
	Deduct			
7.	Capital cost allowance	231.4	231.4	
8.	Items capitalized for regulatory purposes	45.9	45.9	
9.	Deduction for "grossed up" Part VI.1 tax	3.5	3.5	
10.	Amortization of share/debenture issue expense	3.9	3.9	
11.	Amortization of cumulative eligible capital	0.3	0.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site restoration cost adjustment	68.1	68.1	
14.	Cash based pension and OPEB costs	44.3	44.3	
15.	Total Deduction	397.6	397.6	
16.	Taxable income	237.9	237.9	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	35.7	27.4	63.1
19.	Part VI.1 tax			1.2
20.	Total taxes excluding interest shield			64.3
	Tax shield on interest expense			
21.	Rate base	4,373.8		
22.	Return component of debt	3.35%		
23.	Interest expense	146.5		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(38.8)
26.	Total utility income taxes			25.5

Witness: K. Culbert

COST OF SERVICE
2014 FISCAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,455.9	-	1,455.9
2.	Operation and maintenance	436.2	(10.9)	425.3
3.	Depreciation	262.4	(0.7)	261.7
4.	Amortization	1.1	-	1.1
5.	Depreciation and amortization	263.5	(0.7)	262.8
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	41.4	(0.2)	41.2
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	41.4	(0.2)	41.2
10.	Interest on long-term debt	142.8	(142.8)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.6	(3.6)	-
				-
12.	Interest and financing amortization	146.4	(146.4)	-
13.	Interest on short-term debt	8.9	(8.9)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	35.7	(35.7)	-
16.	Total operating costs	2,381.0	(193.9)	2,187.1
17.	Current taxes	16.7	(16.7)	-
18.	Deferred taxes	1.1	(1.1)	-
19.	Income tax expense	17.8	(17.8)	-
20.	Cost of service	2,398.8	(211.7)	2,187.1

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2014 FISCAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(10.9)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	1.3
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.7)
		To eliminate Corporate Cost allocations above RCAM amount.	(9.7)
			(10.9)
3.	(0.7)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.6)
			(0.7)
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2014 FISCAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
10.	(142.8)	Interest on long-term debt Expense of capital.
11.	(3.6)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
13.	(8.9)	Interest on short-term debt Expense of capital.
14.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
17.	(16.7)	Income taxes - current Income tax expense related to corporate earnings.
18.	(1.1)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2014 FISCAL 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 F2014	Col 8 UCC Carry Forward
1	1,788,040,222	-	-	-	4.00%	(71,521,609)	1,716,518,613
51	1,447,094,880	317,203,379	300,000	158,751,690	6.00%	(96,350,794)	1,668,247,465
2	114,203,948	-	(534,232)	(267,116)	6.00%	(6,836,210)	106,833,506
6	12,284	-	-	-	10.00%	(1,228)	11,056
8	11,848,709	8,111,000	-	4,055,500	20.00%	(3,180,842)	16,778,867
10	17,492,214	5,160,438	(382,375)	2,389,032	30.00%	(5,964,374)	16,305,903
12	14,869,893	25,643,922	-	12,821,961	100.00%	(27,691,854)	12,821,961
12	-	-	-	-	-	-	-
17	29,793	-	-	-	8.00%	(2,383)	27,410
38	4,701,123	798,750	(61,000)	368,875	30.00%	(1,520,999)	3,917,874
41	42,660,878	16,426,029	-	8,213,015	25.00%	(12,718,473)	46,368,434
13	8,994,431	4,920,000	-	2,460,000	-	(249,000)	13,665,431
3	224,883	-	-	-	5.00%	(11,244)	213,639
45	269,361	-	-	-	45.00%	(121,213)	148,149
50	8,195,764	5,000,000	-	2,500,000	55.00%	(5,882,670)	7,313,094
52	-	-	-	-	100.00%	-	-
Total	3,458,638,383	383,263,518	(677,607)	191,292,956		(232,052,894)	3,609,171,400

Non-utility and shared asset eliminations	679,529
Utility Federal CCA	(231,373,365)

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 F2014	UCC Carry Forward
1	1,788,040,222	-	-	-	4.00%	(71,521,609)	1,716,518,613
51	1,447,094,880	317,203,379	300,000	158,751,690	6.00%	(96,350,794)	1,668,247,465
2	114,203,948	-	(534,232)	(267,116)	6.00%	(6,836,210)	106,833,506
6	12,284	-	-	-	10.00%	(1,228)	11,056
8	11,848,709	8,111,000	-	4,055,500	20.00%	(3,180,842)	16,778,867
10	17,492,214	5,160,438	(382,375)	2,389,032	30.00%	(5,964,374)	16,305,903
12	14,869,893	25,643,922	-	12,821,961	100.00%	(27,691,854)	12,821,961
12	-	-	-	-	-	-	-
17	29,793	-	-	-	8.00%	(2,383)	27,410
38	4,701,123	798,750	(61,000)	368,875	30.00%	(1,520,999)	3,917,874
41	42,660,878	16,426,029	-	8,213,015	25.00%	(12,718,473)	46,368,434
13	8,994,431	4,920,000	-	2,460,000	-	(249,000)	13,665,431
3	224,883	-	-	-	5.00%	(11,244)	213,639
45	269,361	-	-	-	45.00%	(121,213)	148,149
50	8,195,764	5,000,000	-	2,500,000	55.00%	(5,882,670)	7,313,094
52	-	-	-	-	100.00%	-	-
Total	3,458,638,383	383,263,518	(677,607)	191,292,956		(232,052,894)	3,609,171,400

Non-utility and shared asset eliminations	679,529
Utility Provincial CCA and UCC	(231,373,365)

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2014 FISCAL YEAR AND 2013 BOARD APPROVED

Item No.		Col. 1 2014 Budget ($Millions)	Col. 2 2013 Board Approved Budget ($Millions)	Col. 3 2014 Budget Over/(Under) 2013 Budget ($Millions)	
1.1	Gas costs charged to operations	1,455.9	1,342.8	113.1	/u
1.2	Operations and maintenance	425.3	415.1	10.2	
1.3	Depreciation	262.8	279.3	(16.5)	
1.4	Fixed financing costs	1.9	2.3	(0.4)	
1.5	Municipal and other taxes	41.2	39.3	1.9	
1.0	Total costs and expenses	2,187.1	2,078.8	108.3	/u

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2014 FISCAL YEAR AND 2013 BOARD APPROVED

Item No.

1.1 Gas costs charged to operations - increase of $113.1million /u

The increase in gas costs charged to operations in the 2014 Budget is primarily due to a higher commodity price in 2014 compared to 2013, general service customer growth and continued migration from T-service to system gas; partially offset by a lower gas demand forecast resulting from the continued decline in average use for general service customers and forecasted warmer weather. Please refer to Exhibit C3, Tab 2, Schedule 1 for the details of the gas volume budget.

1.2 Operation and maintenance - increase of $10.2 million

The increase in operation and maintenance costs in the 2014 Budget is due to higher salaries and wages due to an increase in base salaries and an increase in outsourced services costs; partially offset by lower pension expense and other post-employment benefits (OPEB) as a result of a greater return on assets driven by an expected increase in plan assets.

A comparison of the 2014 Budget to the 2013 Board Approved operation and maintenance costs is provided at Exhibit D1, Tab 3, Schedule 1.

1.3 Depreciation expense – decrease of $16.5 Million

The decrease in depreciation expense is due to lower proposed depreciation rates in 2014 compared the 2013 Board Approved rates; partially offset by a higher opening balance.

Witnesses: S. Kancharla
R. Lei

1.4 Fixed financing costs – decrease of $0.4 million

The decrease in fixed financing costs is due to the decrease in credit facility fees and rating agency fees.

1.5 Municipal and other Taxes – increase of $1.9 million

The increase reflects the inflationary pressure on municipal tax rate, increased municipal taxes in growth for new mains and service connections. The details of municipal taxes are provided at Exhibit D1, Tab 6, Schedule 1.

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2014 Fiscal Year

Line No.	Particulars ($ 000's)	Budget 2014
1.	Operations	$ 65,800
2.	Pipeline Integrity & Engineering	39,004
3.	Human Resources and Facilities	21,972
4.	Employee Benefits	25,756
5.	Short Term Incentive Program	21,156
6.	Information Technology	26,387
7.	Regulatory, Public and Government Affairs	22,589
8.	Finance	11,717
9.	Provision for Uncollectibles (Bad Debts)	9,500
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,334
11.	Business Development & Customer Strategy (excluding DSM)	6,185
12.	Legal and Corporate Security	5,253
13.	Energy Supply and Policy	4,243
14.	Non-Departmental	3,589
15.	Capitalization (A&G)	(35,500)
16.	Interest on Security Deposit	1,313
17.	Regulatory Eliminations	(3,276)
18.	Other O&M	228,022
19.	Customer Care/CIS Service Charges	92,631
20.	Pensions and OPEB Costs	37,248
20.	Corporate Cost Allocations (including direct costs)	44,977
21.	Demand Side Management Programs (DSM)	32,159
22.	Conservation Services	1,976
23.	Subtotal	437,013
	Other Regulatory Eliminations	
24.	To eliminate Corporate Cost Allocations above RCAM	(9,695)
25.	To eliminate Conservation Services and Overheads	(1,976)
26.	Total Eliminations	(11,671)
27.	Total Net Utility O&M Expense	$ 425,342

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2014 Fiscal Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2014 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 170,572	$ 167,670	$ 2,902	1.7%
2.	Benefits	25,756	25,261	495	2.0%
3.	Short Term Incentive Program	21,156	20,700	456	2.2%
4.	Employee Training and Development	4,973	4,751	222	4.7%
5.	Materials and Supplies	5,168	5,309	(142)	-2.7%
6.	Outside Services	86,090	83,710	2,381	2.8%
7.	Consulting	4,732	5,082	(350)	-6.9%
8.	Repairs and Maintenance	2,376	2,343	33	1.4%
9.	Fleet	10,354	10,213	141	1.4%
10.	Rents and Leases	7,383	7,338	45	0.6%
11.	Telecommunications	3,742	3,637	106	2.9%
12.	Travel and Other Business Expenses	5,042	5,387	(345)	-6.4%
13.	Memberships	5,026	5,010	17	0.3%
14.	Claims, Damages and Legal Fees	940	863	77	8.9%
15.	Interest on Security Deposits	1,313	780	533	68.3%
16.	Provision for Uncollectibles	9,500	9,500	-	0.0%
17.	Legal Fees	2,759	2,700	59	2.2%
18.	Audit Fees	1,616	1,594	22	1.4%
19.	Other	4,609	4,545	64	1.4%
20.	Internal Allocations and Recoveries	(29,488)	(29,900)	412	-1.4%
21.	Capitalization (A&G)	(35,500)	(37,795)	2,295	-6.1%
22.	Capitalization	(76,820)	(75,451)	(1,370)	1.8%
23.	Regulatory Eliminations	(3,276)	(4,049)	773	-19.1%
24.	Other O&M	228,022	219,197	8,825	4.0%
25.	Customer Care/CIS Service Charges	92,631	89,444	3,187	3.6%
26.	Pension and OPEB Costs	37,248	42,800	(5,552)	-13.0%
27.	Corporate Cost Allocations (including direct costs)	44,977	45,761	(784)	-1.7%
28.	Demand Side Management Programs (DSM)	32,159	31,588	571	1.8%
29.	Conservation Services	1,976	2,728	(752)	-27.6%
30.	Subtotal	437,013	431,519	5,494	1.3%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(9,695)	(13,666)	3,971	-29.1%
32.	To eliminate Conservation Services	(1,976)	(2,728)	752	-27.6%
33.	Total Eliminations	(11,671)	(16,394)	4,723	-28.8%
34.	Total Net Utility O&M Expense	$ 425,342	$ 415,125	$ 10,217	2.5%
35.	FTE's	2,377	2,388	-11	-0.5%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2014 Budget Year

Salary Bands	Col. 1 FTE	Col. 2 Total Salaries ($000's)	Col. 3 Average Salary ($000's)
1. Management	154	$ 23,569	$ 153.0
2. Supervisory	1,484	119,254	80.4
3. Unionized	739	45,855	62.0
4. Total	2,377	$ 188,678	$ 79.4

Witnesses: S. Kancharla
R. Lei
S. Trozzi

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	2,932,223.6	364,714.7	124.382	3.300
1.3	Western - @ Nova - TCPL	938,105.2	117,147.7	124.877	3.313
1.4	Western Buy/Sell - with Fuel	1,326.7	168.6	127.094	3.372
1.5	Western - @ Alliance	962,756.8	125,441.6	130.294	3.457
1.6	Less TCPL Fuel Requirement	(72,504.3)	0.0		
1.	Total Western Canadian Supplies	4,761,908.0	607,472.6	127.569	3.385
2.	Peaking Supplies	36,068.0	8,637.9	239.488	6.354
3.	Ontario Production	730.0	130.6	178.843	4.745
4.	Chicago Supplies	1,847,142.8	271,897.1	147.199	3.906
5.	Delivered Supplies	924,668.5	150,356.2	162.606	4.314
6.	Total Supply Costs	7,570,517.3	1,038,494.3	137.176	3.640
	Transportation Costs				
7.1	TCPL - FT - Demand		229,942.4		
7.2	- FT - Commodity	3,799,151.2	0.0	-	-
7.3	- Parkway to CDA		3,410.5		
7.4	- STS - CDA		12,924.1		
7.5	- STS - EDA		9,436.8		
7.6	- Dawn to CDA		9,226.6		
7.7	- Dawn to EDA		18,173.0		
7.8	- Dawn to Iroquois		6,129.2		
7.9	Other Charges		0.0		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		43,550.1		
7.12	Vector Pipeline		25,929.2		
7.	Total Transportation Costs		365,761.4		
8.	Total Before PGVA Adjustment	7,570,517.3	1,404,255.7	185.490	4.921
9.	PGVA Adjustment		(88,369.7)		
10.	Total Purchases & Receipt	7,570,517.3	1,315,886.0	173.817	4.612

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	7,570,517.3	1,315,886.0	173.817	4.612
11.	Storage Fluctuation	(86,272.7)	(14,995.7)		
12.	Commodity Cost to Operations	7,484,244.5	1,300,890.3	173.817	
13.	Storage and Transportation Costs		105,281.1		
14.	Gas Cost to Operations	7,484,244.5	1,406,171.5	187.884	4.985
15.	Western T-Service		49,681.4		
16.	Forecasted Gas Costs	7,484,244.5	1,455,852.8	194.522	5.161

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2014

Item #		
1.	Sendout To Operations	7,484,244.5
2.	T-Service Volumes	3,747,940.5
3.	Total Sendout	11,232,185.0
4.1	Residential Sales	4,131,122.5
4.2	Commercial Sales	2,645,971.2
4.3	Industrial Sales	450,613.0
4.4	T-Service	3,733,346.0
4.5	Rate 200 T-Service (Gazifere)	41,475.4
4.6	Rate 200 Sales (Gazifere)	123,411.8
4.7	Company Use	4,197.7
4.8	Unaccounted For (UAF)	77,660.0
4.9	Unbilled Forecast - Sales	27,504.9
4.10	Unbilled Forecast - T-Service	(26,880.9)
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,232,185.0

SUMMARY OF STORAGE & TRANSPORTATION COST
FISCAL 2014

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2014	Col. 2 Fiscal 2014 Storage Charges Recovered in Fiscal 2014	Col. 3 Fiscal 2013 Storage Charges Recovered in Fiscal 2014	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2013
	Storage				
1.1	Chatham D	132.3	75.0	57.8	132.8
1.2	Injection	90.5	27.1	84.5	111.7
1.3	Withdrawal	69.5	69.5	0.0	69.5
1.4	Market Based Storage	17,412.0	9,576.1	7,493.4	17,069.5
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	1,279.0	1,279.0	1,396.8	2,675.8
1.	Total Storage	18,983.4	11,026.8	9,032.4	20,059.2
2.	Total Transportation	66,402.7	36,530.0	29,710.7	66,240.7
	Dehydration				
3.1	Demand	1,012.6	557.0	453.7	1,010.8
3.2	Commodity	207.2	207.2	0.0	207.2
3.	Total Dehydration	1,219.8	764.3	453.7	1,218.0
4.	Total Storage & Other Costs	86,605.8	48,321.1	39,196.8	87,517.9
	Fuel Costs				
5.1	Tecumseh	3,002.8	1,975.8	1,176.2	3,152.0
5.2	Union Storage	671.6	417.2	378.3	795.5
5.3	Union Transportation	13,649.2	13,509.3	306.3	13,815.6
5.	Total Fuel Costs	17,323.6	15,902.3	1,860.7	17,763.1
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	103,929.4	64,223.4	41,057.6	105,281.0
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				105,281.0

	2013 Budget Peak Day Demand	Column 1	Column 2	Column 3	2014 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,229,260	592,864	3,822,124	Demand	3,288,088	673,262	3,961,350
2.	Less Curtailment	(129,737)	(31,788)	(161,524)	Less Curtailment	(133,995)	(28,705)	(162,700)
3.		3,099,523	561,076	3,660,600		3,154,093	644,557	3,798,650
4.	TCPL FT Capacity	63,468	197,421	260,889	TCPL FT Capacity	271,468	370,627	642,095
5.	TCPL STFT	302,500	90,000	392,500	TCPL STFT	-	-	-
6.	TCPL Short Haul	147,318	114,000	261,318	TCPL Short Haul	151,818	114,000	265,818
7.	TCPL STS	369,464	80,611	450,076	TCPL STS	369,464	80,611	450,075
8.	Ontario T-Service	308,176	28,137	336,313	Ontario T-Service	300,354	26,576	326,930
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	32,753	-	32,753	Delivered Service	182,738	-	182,738
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,505	52,753	158,258
12.	Total Supply	3,104,212	562,922	3,667,134	Total Supply	3,156,374	644,567	3,800,941
13.	Sufficency/(Deficiency)	4,688	1,846	6,535	Sufficency/(Deficiency)	2,281	10	2,291

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/10^{3}m^3 Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-14	3.2267	3.8242	3.9370	1.0451	
Feb-14	3.2260	3.8259	3.9337	1.0459	
Mar-14	3.1920	3.7927	3.8905	1.0466	
Apr-14	3.1686	3.7358	3.7301	1.0474	
May-14	3.1813	3.7572	3.7512	1.0481	
Jun-14	3.1876	3.7883	3.7825	1.0489	
Jul-14	3.2109	3.8211	3.8111	1.0497	
Aug-14	3.2216	3.8378	3.8238	1.0505	
Sep-14	3.2373	3.8382	3.8236	1.0513	
Oct-14	3.3159	3.8592	3.8525	1.0521	
Nov-14	3.5150	3.9403	3.9634	1.0529	
Dec-14	3.6284	4.1052	4.1310	1.0537	
	3.2759	3.8438	3.8692	1.0494	123.4698
TCPL Fuel Ratio		1.91%			125.8270

(Note 1) $CAD/10^{3}m^3 = $CAD/GJ * 37.69 Mj/m3

21 Day Period **2-Aug-13** **to** **30-Aug-13**

Natural Gas Conversions

mcf times 0.028328 = 10^{3}m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $/10^{3}m^3

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $/10^{3}m^3

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Gas Supply/Demand Balance

Item #		Col. 1 2014 Budget 10^3m^3	Col. 2 2013 Budget 10^3m^3
1.	Total Demand	11,232,185.0	11,576,371.2
	Deliveries		
2.1	Western Canadian Supplies	4,761,908.0	3,886,090.9
2.2	Peaking/Seasonal	36,068.0	37,998.7
2.3	Ontario Production	730.0	730.0
2.4	Chicago Supplies	1,847,142.8	1,832,109.7
2.5	Delivered Supplies	924,668.5	1,553,462.5
2.6	Direct Purchase Delivery	3,742,271.6	4,383,689.4
2.7	Storage (Injection)/Withdrawal	(80,603.8)	(117,710.0)
2.	Total Delivery	11,232,185.0	11,576,371.2

Total Demand includes both System Sales and T-Service Consumption

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

Producing the UUF Forecast – 2014 Test Year & 2015-2016 Forecasts

1. This evidence describes the forecast methodology and updates the forecast of Unbilled and Unaccounted-For Gas ("UUF") for the 2014 test year. Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") asks the Board to approve the 2014 UUF forecast of 78,284 10^3m^3 as part of the 2014 volumes budget, as well as the continued use of the Unaccounted-For Variance Account ("UAFVA"). Deferral account evidence can be found at Exhibit D1 Tab 8, Schedule 1.

2. Only the 2014 UUF is subject to approval in this proceeding as the Company intends to update 2015 & 2016 UUF in subsequent annual adjustments as detailed at Exhibit A2, Tab 1, Schedule 1. For the purpose of generating preliminary rate impacts for 2015 and 2016, UUF forecasts are provided for those years as outlined in paragraphs 6, 10 and 11 below. The 2016 forecast is used as a proxy basis for generating preliminary rate impacts 2017 and 2018

3. The UUF forecast is produced using a two-step process involving the forecast of both Unaccounted-For Gas ("UAF") and unbilled volumes. For instance, the 2014 UUF forecast is equal to the 2014 UAF forecast plus the expected difference between the December 2014 and December 2013 unbilled volumes (i.e., change in unbilled volumes). Both the UAF and unbilled volumes forecasts are produced via a statistical model.

Witnesses: H. Sayyan
M. Suarez

4. UAF data for years prior to 2005 have been transformed to calendar year format in order to produce a calendar year UAF forecast. For an explanation of the transformation of volumes from fiscal to calendar year format, please see EB-2006-0034, Exhibit C1, Tab 3, Schedule 1.

Unbilled Volumes

5. The Company uses a regression model to forecast the level of unbilled volumes. The model relies on the high degree of correlation between volumes and degree days.

6. As noted in paragraph 3, the UUF forecast necessitated year-end unbilled volumes forecasts for 2013 and 2014 to forecast 2014 UUF. For preliminary 2015 and 2016 forecasts, the level of unbilled volumes was held constant as underlying degree days are assumed constant over this period. As a result, the change in unbilled volumes or net impact of constant unbilled volumes is zero. It is the Company's intent to update its degree day and unbilled forecasts as part of the annual volumetric updates for 2015 and 2018.

Unaccounted For Gas Forecast (UAF)

7. The Company regularly tests a variety of forecasting models in order to ensure that the UAF forecasts are as accurate as possible. These models incorporate multiple explanatory variables to model the variability in UAF actuals. For a number of years now, the same regression model that features the number of unlocked customers (i.e., unlocks) as an independent variable has continued to show the highest degree of relative accuracy. The rationale for including unlocks as an explanatory variable is that the greater the size of the distribution system, the greater the level of UAF volume, holding other things constant. Thus the

expectation is that the coefficient on the unlock variable (i.e., β_1 in Figure 1) will be positive.

Figure 1
UAF forecasting model specification[1]

$$UAF_t = \beta_0 + \beta_1 * LOG(ULKS)_t + \beta_2 * DUM02_t + \beta_3 * DUMNEG_t + \varepsilon_t$$

8. The model also includes variables to account for a structural change in 2002, as well as a negative UAF value. Since the UAF values are generally lower after 2002 compared to before 2002, the expectation is that the coefficient on the corresponding variables will be negative. Further, the expectation is that the variable that accounts for the negative UAF value will have a negative coefficient. Including the variable to account for the negative values in 2004 ensures that the forecast is greater than zero. As the term ‘unaccounted-for’ suggests, it is expected that billed consumption will be less than sendout volumes and thus UAF volumes should be greater than zero.

9. The proposed model specification (model ‘A’) performs well relative to other models, as demonstrated in Table 1 provided below. It produces an in-sample forecast error of five percent and an out-of-sample forecast error of six percent in 2012, the last year of available actual data. Meanwhile, the other specifications yield larger errors. Figure 2 provided below gives the meaning of the independent variables in Table 1.

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[1] The UAF model is specified as a linear equation of the following form:

UAF =	-2820813	+ 2064798 * LOG(ULKS)	– 103600 * DUM02	– 59080 * DUMNEG	
(t-stats in parentheses)	(-3.39)	(3.49)	(-4.36)	(-2.11)	

R^2 = 0.63 F-statistic=10.24 Prob(F-statistic)=0.00

Table 1
UAF model specification testing results (volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*
Model	**Dependent Variable**	**Independent Variable(s)**	**2012 In-Sample Forecast**	**Percent Error (Forecast - Actual)**	**2012 Out-of-Sample Forecast**	**Percent Error (Forecast - Actual)**
A	UAF	LOG(ULKS), DUM02, DUMNEG	70,891	-5.2%	70,237	-6.1%
B	UAF	LOG(ULKS), DUM02	67,431	-9.8%	66,231	-11.4%
C	UAF	LOG(VOLPERCUST), DUM02, DUMNEG	50,435	-32.5%	47,706	-36.2%
D	UAF	LOG(ULKS), DUM02, DUMNEG, UAF(-1)	70,356	-5.9%	69,542	-7.0%
E	UAF	LOG(TSVOL), DUM02, DUMNEG	46,322	-38.0%	42,762	-42.8%
F	UAF	DUM02, DUMNEG, AR(1), MA(1)	79,104	5.8%	86,738	16.0%
G	UAF	LOG(CAPEX), DUM02, DUMNEG, TREND	81,573	9.1%	83,911	12.2%

Figure 2
Mnemonics of variables used in testing

Col. 1	*Col. 2*
Mnemonic	**Definition**
ULKS	Unlocked customers/meters (unlocks)
DUM02	Dummy variable to account for 2002 structural break
DUMNEG	Dummy variable to account for negative UAF values
VOLPERCUST	Volume per general service customer
UAF(-1)	UAF lagged one year
TSVOL	T-Service volumes
CAPEX	Capital expenditures (customer-related system improvements and upgrades)
AR(N)	N-th order auto-regressive term
MA(N)	N-th order moving average term
TREND	Time (year)

10. The 2014 UAF forecast is produced by model 'A' using data until 2012, the last full year of available actuals. To derive estimates for 2015 and 2016, the 2014 UAF forecast is divided by the proposed 2014 throughput volumes (Exhibit C3, Tab 2, Schedule 1 less Rate 300 volumes) to obtain the ratio of UAF to throughput volume. The resulting 2014 UAF to throughput ratio is 0.7% (77.7/(11,156.0 – 30.0 10^3m^3). This ratio is applied to 2015 and 2016 total throughput volumes (as shown at Exhibit C4, Tab 2, Schedule 1, and Exhibit C5, Tab 2, Schedule 1) to arrive at a representative UAF forecast for those respective years. It is the Company's intent to update the 2015 UAF forecast as part of the 2015 annual volumetric update in

Custom IR using the most accurate model as assessed by the inclusion of actual data to 2013. The 2016 to 2018 UAF will be updated in the same way in the following years.

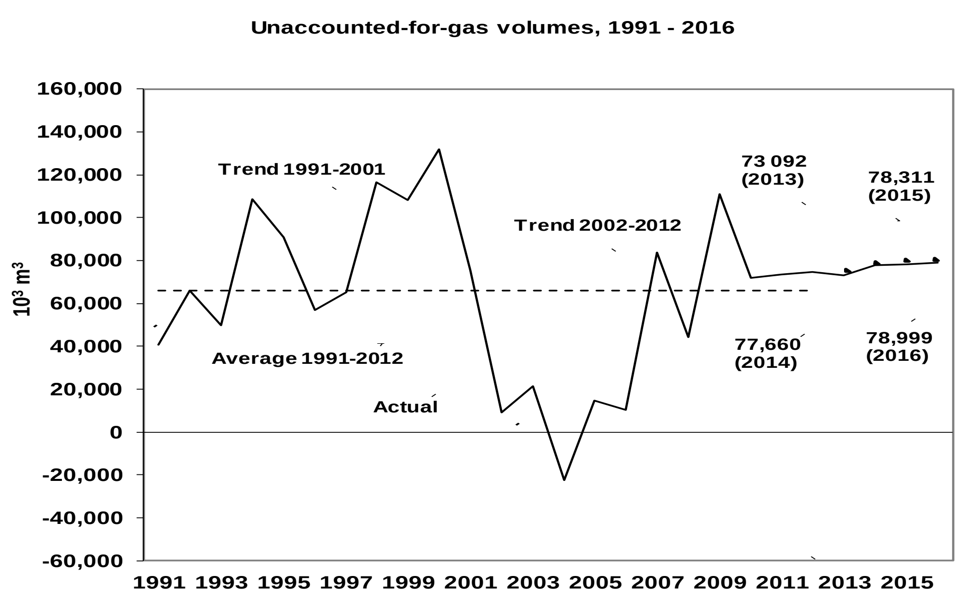
11. The resulting UAF estimates for 2015 and 2016 are shown in Table 2.

Table 2

2015 & 2016 UAF forecasts (volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4 = Col. 2 * Col. 3*
Calendar Year	**Throughput**	**2014 UAF to Throughput Ratio**	**UAF Forecast**
2015	11,249,414	0.7%	78,311
2016	11,348,299	0.7%	78,999

12. Figure 3 shows historical UAF data to 2012 along with the 2013 Board Approved, 2014 Test Year as well as 2015 and 2016 forecasts. The graph also shows the 1991 to 2001 trend, the 2002 to 2012 and the 1991 to 2012 average.



***Forecast values are based on a regression model produced in February 2013**.

Witnesses: H. Sayyan
M. Suarez

Actual versus Board Approved– Last Five Years

13. Table 3 below presents UAF actuals along with Board Approved values for the past five years.

Table 3
UAF Actuals vs Board Approved

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Actual**	**Board Approved**
2008	44,424	39,444
2009	110,917	31,841
2010	72,104	37,795
2011	73,355	64,211
2012	74,762	68,925

Calculation of 2014 UUF

14. The total UUF forecast is generated by adding the forecasted change in December 2014 versus December 2013 unbilled volumes to the 2014 UAF forecast. As such, the 2014 Test Year UUF forecast is as follows:

2014 UUF = (Forecast of UAF Gas) + (Change in Unbilled Gas)
= (Forecast of UAF Gas) + (Forecast of December 2014 Unbilled Gas - Forecast for December 2013 Unbilled Gas)
$= 77\,660\ 10^3 m^3 + (704\,606\ 10^3 m^3 – 703\,982\ 10^3 m^3)$
$= 77\,660\ 10^3 m^3 + 624\ 10^3 m^3$
$= 78\,284\ 10^3 m^3$

Witnesses: H. Sayyan
M. Suarez

15. Table 4 below displays the historical UAF and unlock data used in the selected regression model to generate the forecast UAF for the 2014 test year.

Table 4
UAF Volumes and total unlocks, calendar 1991 to 2014
(volumes in 10^3m^3)

Col. 1 Calendar Year	*Col. 2* UAF Volumes	*Col. 3* Unlocks
1991	40,662	1,067,691
1992	66,028	1,104,224
1993	49,782	1,146,420
1994	108,765	1,188,226
1995	90,655	1,232,989
1996	56,739	1,274,338
1997	65,228	1,325,700
1998	116,376	1,376,564
1999	108,201	1,426,783
2000	132,021	1,479,413
2001	75,606	1,529,651
2002	9,284	1,580,819
2003	21,412	1,635,855
2004	-22,406	1,688,843
2005	14,815	1,735,906
2006	10,274	1,782,813
2007	83,823	1,824,789
2008	44,424	1,865,020
2009	110,917	1,887,605
2010	72,104	1,926,294
2011	73,355	1,960,378
2012	74,762	1,994,900
2013 Board Approved	73,092	2,026,392
2014 Test Year*	77,660	2,059,619

*Forecast values are based on a regression model produced in February 2013.

Witnesses: H. Sayyan
M. Suarez

Calculation of 2015 and 2016 UUF

16. The forecast of December 2015 and December 2016 unbilled volumes are held constant at December 2014 levels as described at paragraph 6. Consequently, there is no change in unbilled volumes for 2015 and 2016. The resulting UUF estimates for those years are hence equal to the UAF forecasts of 78,311 10^3m^3 and 78,999 10^3m^3, respectively.

2014 Test Year Forecast versus 2013 Board Approved

17. Table 5 compares 2014 Test Year Forecast and 2013 Board Approved UUF volumes. The 2013 Board Approved UUF is equal to the 2013 Board Approved UAF plus the change in forecast unbilled gas volumes between December 2013 and December 2012.

Table 5
2014 Test Year Forecast versus 2013 Board Approved (10^3 m^3)

Col. 1	*Col. 3*	*Col. 2*
	2014 Test Year	**2013 Board Approved**
Unaccounted-for volumes	77,660	73,092
Change in unbilled	624	1,088
Unbilled and unaccounted-for	78,284	74,180

Witnesses: H. Sayyan
M. Suarez

COST OF SERVICE
2015 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Normalizing and Other Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,606.8	-	1,606.8
2.	Operation and maintenance	428.5	(96.5)	332.0
3.	Depreciation and amortization expense	276.6	(12.7)	263.9
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	43.1	-	43.1
6.	Operating costs	2,356.9	(109.2)	2,247.7
7.	Income tax expense			6.1
8.	Cost of service			2,253.8

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2015 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(96.5)	Operation and Maintenance To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	318.8	318.8	
	Add			
2.	Depreciation and amortization	263.9	263.9	
3.	Accrual based pension and OPEB costs	33.8	33.8	
4.	Other non-deductible items	1.1	1.1	
5.	Total Add Back	298.8	298.8	
6.	Sub-total	617.6	617.6	
	Deduct			
7.	Capital cost allowance	279.5	279.5	
8.	Items capitalized for regulatory purposes	46.8	46.8	
9.	Deduction for "grossed up" Part VI.1 tax	4.2	4.2	
10.	Amortization of share/debenture issue expense	3.3	3.3	
11.	Amortization of cumulative eligible capital	5.0	5.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.4	0.4	
13.	Site Rest Costs adjustment	63.1	63.1	
14.	Cash based pension and OPEB costs	39.6	39.6	
15.	Total Deduction	441.9	441.9	
16.	Taxable income	175.7	175.7	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	26.4	20.2	46.6
19.	Part VI.1 tax			1.4
20.	Total taxes excluding interest shield			48.0
	Tax shield on interest expense			
21.	Rate base	4,752.5		
22.	Return component of debt	3.32%		
23.	Interest expense	157.9		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(41.9)
26.	Total utility income taxes			6.1

Witness: K. Culbert

COST OF SERVICE
2015 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,606.8	-	1,606.8
2.	Operation and maintenance	440.2	(11.7)	428.5
3.	Depreciation	275.9	(0.8)	275.1
4.	Amortization	1.5	-	1.5
5.	Depreciation and amortization	277.4	(0.8)	276.6
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	43.3	(0.2)	43.1
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	43.3	(0.2)	43.1
10.	Interest on long-term debt	154.5	(154.5)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.3	(3.3)	-
				-
12.	Interest and financing amortization	157.8	(157.8)	-
13.	Interest on short-term debt	19.8	(19.8)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	46.6	(46.6)	-
16.	Total operating costs	2,574.0	(217.1)	2,356.9
17.	Current taxes	(1.1)	1.1	-
18.	Deferred taxes	0.9	(0.9)	-
19.	Income tax expense	(0.2)	0.2	-
20.	Cost of service	2,573.8	(216.9)	2,356.9

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2015 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(11.7)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.0
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.7)
		To eliminate Corporate Cost allocations above RCAM amount.	(11.2)
			(11.7)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2015 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
10.	(154.5)	Interest on long-term debt Expense of capital.
11.	(3.3)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
13.	(19.8)	Interest on short-term debt Expense of capital.
14.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
17.	1.1	Income taxes - current Income tax expense related to corporate earnings.
18.	(0.9)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2015 FORECAST 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 F2015	Col 8 UCC Carry Forward
1	1,716,518,613	-	-	-	4.00%	(68,660,745)	1,647,857,869
51	1,668,247,465	824,908,997	800,000	412,854,499	6.00%	(124,866,118)	2,369,090,344
2	106,833,506	-	(560,944)	(280,472)	6.00%	(6,393,182)	99,879,380
6	11,056	-	-	-	10.00%	(1,106)	9,950
8	16,778,867	8,266,000	-	4,133,000	20.00%	(4,182,373)	20,862,494
10	16,305,903	5,222,538	(401,494)	2,410,522	30.00%	(5,614,928)	15,512,020
12	12,821,961	65,297,676	-	32,648,838	100.00%	(45,470,799)	32,648,838
12	-	-	-	-	-	-	-
17	27,410	-	-	-	8.00%	(2,193)	25,217
38	3,917,874	798,750	(64,050)	367,350	30.00%	(1,285,567)	3,367,007
41	46,368,434	15,893,388	-	7,946,694	25.00%	(13,578,782)	48,683,040
13	13,665,431	3,120,000	-	1,560,000	-	(249,000)	16,536,431
3	213,639	-	-	-	5.00%	(10,682)	202,957
45	148,149	-	-	-	45.00%	(66,667)	81,482
50	7,313,094	21,000,000	-	10,500,000	55.00%	(9,797,202)	18,515,892
52	-	-	-	-	100.00%	-	-
Total	3,609,171,400	944,507,349	(226,488)	472,140,431		(280,179,342)	4,273,272,919

Non-utility and shared asset eliminations	722,789
Utility Federal CCA	(279,456,553)

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 F2015	UCC Carry Forward
1	1,716,518,613	-	-	-	4.00%	(68,660,745)	1,647,857,869
51	1,668,247,465	824,908,997	800,000	412,854,499	6.00%	(124,866,118)	2,369,090,344
2	106,833,506	-	(560,944)	(280,472)	6.00%	(6,393,182)	99,879,380
6	11,056	-	-	-	10.00%	(1,106)	9,950
8	16,778,867	8,266,000	-	4,133,000	20.00%	(4,182,373)	20,862,494
10	16,305,903	5,222,538	(401,494)	2,410,522	30.00%	(5,614,928)	15,512,020
12	12,821,961	65,297,676	-	32,648,838	100.00%	(45,470,799)	32,648,838
12	-	-	-	-	-	-	-
17	27,410	-	-	-	8.00%	(2,193)	25,217
38	3,917,874	798,750	(64,050)	367,350	30.00%	(1,285,567)	3,367,007
41	46,368,434	15,893,388	-	7,946,694	25.00%	(13,578,782)	48,683,040
13	13,665,431	3,120,000	-	1,560,000	-	(249,000)	16,536,431
3	213,639	-	-	-	5.00%	(10,682)	202,957
45	148,149	-	-	-	45.00%	(66,667)	81,482
50	7,313,094	21,000,000	-	10,500,000	55.00%	(9,797,202)	18,515,892
52	-	-	-	-	100.00%	-	-
Total	3,609,171,400	944,507,349	(226,488)	472,140,431		(280,179,342)	4,273,272,919

Non-utility and shared asset eliminations	722,789
Utility Provincial CCA and UCC	(279,456,553)

Witness: K. Culbert

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2015 FORECAST AND 2014 FISCAL YEAR

Item No.		Col. 1 2015 Forecast ($Millions)	Col. 2 2014 Budget ($Millions)	Col. 3 2015 Forecast Over/(Under) 2014 Budget ($Millions)	
1.1	Gas costs charged to operations	1,606.8	1,455.9	150.9	/u
1.2	Operations and maintenance	428.5	425.3	3.2	
1.3	Depreciation	276.6	262.8	13.8	
1.4	Fixed financing costs	1.9	1.9	-	
1.5	Municipal and other taxes	43.1	41.2	1.9	
1.0	Total costs and expenses	2,356.9	2,187.1	169.8	/u

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2015 FORECAST AND 2014 FISCAL YEAR

Item No.

1.1 Gas costs charged to operations - increase of $150.9 million /u

The increase in gas costs charged to operations in the 2015 Forecast is primarily due to general service customer growth and continued migration from T-service to system gas; partially offset by the continued decline in average use for residential customers. Please refer to Exhibit C4, Tab 2, Schedule 1 for the details of the gas volume budget.

1.2 Operation and maintenance - increase of $3.2 million

The increase in operation and maintenance costs in the 2015 Forecast is due to higher customer care service charges, higher salaries and wages due to an increase in base salaries and an increase in outsourced services costs; partially offset by lower pension expense and other post-employment benefits (OPEB) as a result of a greater return on assets driven by an expected increase in plan assets, lower RCAM and Ontario hearing costs.

A comparison of the 2015 Forecast to the 2014 Budget operation and maintenance costs is provided at Exhibit D1, Tab 3, Schedule 1.

1.3 Depreciation expense – increase of $13.8 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other Taxes – increase of $1.9 million

The increase reflects the inflationary pressure on municipal tax rate, increased municipal taxes in growth for new mains, service connections and for the GTA Leave to Construct Project. The details of municipal taxes are provided at Exhibit D1, Tab 6, Schedule 1.

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2015 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2015
1.	Operations	$ 67,300
2.	Pipeline Integrity & Engineering	39,874
3.	Human Resources and Facilities	22,462
4.	Employee Benefits	26,350
5.	Short Term Incentive Program	21,628
6.	Information Technology	26,976
7.	Regulatory, Public and Government Affairs	20,914
8.	Finance	11,979
9.	Provision for Uncollectibles (Bad Debts)	9,500
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,399
11.	Business Development & Customer Strategy (excluding DSM)	6,363
12.	Legal and Corporate Security	5,370
13.	Energy Supply and Policy	4,348
14.	Non-Departmental	3,669
15.	Capitalization (A&G)	(36,440)
16.	Interest on Security Deposit	2,019
17.	Regulatory Eliminations	(3,192)
18.	Other O&M	231,520
19.	Customer Care/CIS Service Charges	96,502
20.	Pensions and OPEB Costs	33,764
20.	Corporate Cost Allocations (including direct costs)	45,140
21.	Demand Side Management Programs (DSM)	32,802
22.	Subtotal	439,728
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(11,179)
24.	Total Eliminations	(11,179)
25.	Total Net Utility O&M Expense	$ 428,549

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2015 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2015 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 174,609	$ 167,670	$ 6,939	4.1%
2.	Benefits	26,350	25,261	1,089	4.3%
3.	Short Term Incentive Program	21,628	20,700	928	4.5%
4.	Employee Training and Development	4,783	4,751	33	0.7%
5.	Materials and Supplies	5,226	5,309	(84)	-1.6%
6.	Outside Services	85,682	83,710	1,972	2.4%
7.	Consulting	4,878	5,082	(205)	-4.0%
8.	Repairs and Maintenance	2,410	2,343	67	2.9%
9.	Fleet	10,513	10,213	300	2.9%
10.	Rents and Leases	7,475	7,338	137	1.9%
11.	Telecommunications	3,826	3,637	189	5.2%
12.	Travel and Other Business Expenses	5,090	5,387	(297)	-5.5%
13.	Memberships	5,135	5,010	125	2.5%
14.	Claims, Damages and Legal Fees	963	863	100	11.6%
15.	Interest on Security Deposits	2,019	780	1,239	158.9%
16.	Provision for Uncollectibles	9,500	9,500	-	0.0%
17.	Legal Fees	2,821	2,700	121	4.5%
18.	Audit Fees	1,643	1,594	49	3.1%
19.	Other	4,900	4,545	355	7.8%
20.	Internal Allocations and Recoveries	(29,564)	(29,900)	336	-1.1%
21.	Capitalization (A&G)	(36,440)	(37,795)	1,355	-3.6%
22.	Capitalization	(78,735)	(75,451)	(3,284)	4.4%
23.	Regulatory Eliminations	(3,192)	(4,049)	857	-21.2%
24.	Other O&M	231,520	219,197	12,323	5.6%
25.	Customer Care/CIS Service Charges	96,502	89,444	7,057	7.9%
26.	Pension and OPEB Costs	33,764	42,800	(9,036)	-21.1%
27.	Corporate Cost Allocations (including direct costs)	45,141	45,761	(620)	-1.4%
28.	Demand Side Management Programs (DSM)	32,802	31,588	1,214	3.8%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	439,728	431,519	8,209	1.9%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(11,179)	(13,666)	2,487	-18.2%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(11,179)	(16,394)	5,215	-31.8%
34.	Total Net Utility O&M Expense	$ 428,549	$ 415,125	$ 13,424	3.2%
35.	FTE's	2,364	2,388	-24	-1.0%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2015 Budget Year

Salary Bands	Col. 1 FTE	Col. 2 Total Salaries ($000's)	Col. 3 Average Salary ($000's)
1. Management	153	$ 24,022	$ 157.0
2. Supervisory	1,472	121,189	82.4
3. Unionized	739	47,093	63.7
4. Total	2,364	$ 192,304	$ 81.4

Witnesses: S. Kancharla
R. Lei
S. Trozzi

2015 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 Gas Distribution") during the 2015 Fiscal 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, ie 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.

2. This evidence is provided for the purpose of generating preliminary rate impacts for 2015. As set out at Exhibit A2, Tab 3, Schedule 1, the gas costs will be updated in annual Rate Adjustment proceedings.

Gas Supply

3. Enbridge expects to acquire its system gas supply under the following types of contracts during the Fiscal 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.
- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn Hub
- Niagara Supply: These supplies are forecasted to be acquired at the Niagara Import/Export point.

4. Enbridge Gas Distribution 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 2015 gas supply arrangements.

5. The following is Enbridge's forecast of gas supply acquisition during the 2015 fiscal year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	4 997.9	176.4
Ontario Production	0.7	0.0
Peaking	39.1	1.4
Chicago Supply	1 839.9	65.0
Delivered Supply	741.5	26.2
Niagara Supply	323.7	11.4
	7 942.8	280.4

Witnesses: J. Denomy
D. Small

<u>Commodity Costs</u>

6. 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.

7. 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.

8. The Company prepared its gas supply forecast based upon a 21-day average of various indices from January 31, 2013 to February 28, 2013 for the 12 months commencing January 1, 2015 (Exhibit D4, Tab 3, Schedule 4) and applied these monthly prices to the 2015 budgeted annual volume gas purchases.

9. In an effort to isolate the impact of commodity costs changes the Company removed the impact of the updated price forecast and the April 1, 2013 QRAM prices in a fashion similar to that used in the determination of the 2013 gas cost budget that was filed in EB-2011-0354.

10. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2015 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2015 PGVA. While the Company has prepared the 2015 forecast assuming that it will be acquiring gas in 2015 via traditional transportation paths (ie TCPL, Alliance/Vector) it has also assumed the acquisition of gas at the Niagara interconnect on TCPL effective November 1, 2015. Alternate sources of supply remain as a possibility in the future as more pipeline

projects are being contemplated. Should any other projects materialize the Company will evaluate them at that time.

Peak Day Coverage

11. In EB -2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed at EB-2011-0354, Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2015 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Based upon the information that was available at the time Enbridge is currently forecasting a design peak day level of 105 773$10^3m^3$ (3.7 Bcf) during the winter season of the 2015 fiscal year.

12. Similar to 2014 the Company has chosen to maintain the same level of Peaking Services for 2015 as was forecast for 2014. For purposes of meeting Peak Day Demand in 2015 the Company chose not to rely principally on TCPL STFT service and has looked to other possible solutions in 2015.The driver for this decision is based upon recent events at the National Energy Board (NEB). On March 27, 2013 the NEB issued its decision in TransCanada PipeLines Limited (“TransCanada”) Compliance Filing RH-003-2011. Subsequent to that decision TransCanada filed a Review and Variance Application for 2013 to 2017 with the NEB on May 1, 2013 in relation to RH-003-2011. On June 11, 2013 the “NEB” rendered its decision dismissing in its entirety TransCanada’s Review and Variance Application. On June 12, 2013 TransCanada issued a news release stating their disappointment with the NEB decision and that they were considering all their options including the potential for an appeal. The June 11, 2013 NEB decision also stated that TransCanada must re-file its Tariff Amendments by June 17, 2013 and that they will be considered as a

separate application which will be heard as part of an oral hearing to commence September 3, 2013.

13. The expectation is that the Tariff Amendments that TransCanada proposed as a part of its Review and Variance Application will be the subject of the oral hearing mentioned above. The amended Tariff provisions are intended to provide TransCanada the flexibility required to capitalize on market opportunities for discretionary services as they arise. For example, the current Tariff provisions related to posting STFT availability stipulate that TransCanada post available STFT capacity for five banking days during January 1-15 for the Summer Period (April 1 to October 31) and for five banking days during July 1-15 for the Winter Period (November 1 to March 31). For Summer Period monthly blocks of STFT capacity are posted for five banking days during January 16-31 and for the Winter Period monthly blocks of STFT capacity are posted for a five banking days during July 16-31. TransCanada is proposing to change the five banking day requirement to a period to be determined by TransCanada but no less than one day.

14. Planning for STFT in such an environment would be difficult as the availability of this service might not be known until immediately prior to the period for which it is required. In addition the minimum bid floor would most likely be set at a level higher than the FT toll during the periods that the Company would require STFT, that is, during the winter months when demand for this service is high in order to ensure that it has the assets in place to meet peak day demand in the EDA the Company intends to contract for incremental long haul TCPL FT capacity to the EDA as opposed to relying upon STFT in the winter of 2015. The availability and cost of STFT in the CDA as well as concerns regarding TCPL mainline capacity leads the Company to believe that it may need to rely more on long haul FT

capacity in the CDA in the future. The Company intends to continue to monitor the availability of transport to the franchise and to look for alternatives that will provide value to the customers of EGD while still providing safe and reliable service. If alternatives are found then any differences from the cost of those services and those forecasted as part of the 2015 gas cost will be captured in the 2015 Purchased Gas Variance Account (PGVA). A breakdown of the peak day requirement and supply forecast is shown at Exhibit D4, Tab 3, Schedule 3.

15. Based upon the 2015 volumetric forecast and the level of transportation services to meet peak demand in 2015 the Company is forecasting $26.5million in cost consequences associated with unutilized transportation capacity. Unlike Fiscal 2013 and Fiscal 2014 there is no Design Day Criteria Transportation Deferral Account in Fiscal 2015. Therefore, the total forecast amount of unutilized transportation cost is charged to gas costs. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the April 13 QRAM. Based upon its forecasted gas costs (see Exhibit D4, Tab 3 , Schedule 1, page 2) the Company is forecasting to charge $26.5 million of unutilized transportation costs to gas cost in 2015.

16. As in prior decisions the Company is entitled to capture as part of its' gas cost forecast the cost consequences of any forecasted unutilized long haul TCPL transportation costs. For 2015 this amount translates to $26.5 million and these costs are included as part of the forecasted Storage and Transportation charges that can be found at Exhibit D4, Tab 3, Schedule 2, page 1, line Item # 6. Traditionally these costs would not be eligible for capture and recovery within the current PGVA as previously defined. The Company is currently allowed, however,

to include in the PGVA the impact of changes in TCPL tolls on any forecasted UDC (unutilized demand charge) amount.

17. In its evidence for the 2014 Fiscal Year, the Company proposed a change to the PGVA methodology. Because of the uncertainty arising from the most recent TCPL decision and the impacts that will have on the services the Company may or may not have at its disposal to meet its peak day requirements, the Company has chosen a conservative approach in preparing the 2015 gas costs similar to the approach taken in developing the 2014 forecast. Unlike 2014 however, the Company is proposing to provide an update to its 2015 gas supply portfolio prior to the commencement of the 2015 Fiscal Year and as a part of that update the Company will review the level of unutilized transportation costs at that time and update its gas cost forecast for 2015 as well as whether or not a change to the 2015 PGVA methodology is required.

<u>Transportation</u>

18. 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 2015 Fiscal Year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast contracts were priced based upon current tolls and contracts that had an expiry date during the Fiscal Year were deemed to be renewed with the following exceptions. As discussed earlier the Company has included as part of its 2015 Gas Cost forecast an incremental level of FT service to the EDA. It is contemplated that the Company will acquire 175,000 GJ/day of TCPL FT-NR effective November 1, 2013 for two years expiring October 31, 2015. This is expected to be replaced with 150,000

Gj/day of long haul TCPL FT capacity to the EDA effective November 1, 2015. The inclusion of the incremental long haul capacity, while assisting with the ability to meet peak day will also lower the overall Dawn discretionary requirement in the summer of 2015. The Company has chosen not to renew its contract with the Alliance Pipeline which is set to expire October 31, 2015 as well as two Vector Pipeline contracts totaling 100 000 MMBTU/day also scheduled to expire October 31, 2015. Included in the forecasted supply portfolio effective November 1, 2015 is the acquisition of 200 000 Gj/day of supply at the Niagara interconnect on TCPL. In order to transport that gas from the Niagara import point the Company has assumed the acquisition of 200 000 Gj/day of Niagara Falls to Enbridge Parkway DDA capacity on TCPL. The Company has assumed that effective November 1, 2015 it will contract for 800 000 Gj/day of Union Parkway to Bram West DDA of TCPL capacity (it is expected that 200 000 Gj/day will be assigned to Direct Purchase customers).

19. A copy of the Company’s transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.

20. For the purposes of the 2015 forecast, the Company has assumed the assignment of 42,500 Gj/day of TCPL short haul capacity to Direct Purchase customers and will acquire 42,500 Gj/day of TCPL STFT from November to March.

21. The Company currently 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 has assumed

that effective November 1, 2015, it will contract for an incremental 400 000 Gj/day of M12 capacity (it is expected that 200 000 Gj/day will be assigned to Direct Purchase customers). The Company also has M16 transportation capacity with Union to facilitate the Chatham ”D” Storage pool. The gas cost forecast assumed January 1, 2013 Union tolls.

<u>Storage</u>

22. 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.

23. 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. All three of these cost based contracts have expired and effective April 1, 2010 all of the Company’s contracted third party storage is at market based rates

24. During 2015 the Company will be required to issue an RFP for a storage contract that will expire March 31, 2015. For purposes of the 2015 forecast the cost impacts of the current contract are assumed to be continued in the forecast for 2015 gas costs.

Energy Content

25. 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.

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2015

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	3,300,350.9	461,173.2	139.735	3.707
1.3	Western - @ Nova - TCPL	896,980.2	127,001.7	141.588	3.757
1.4	Western Buy/Sell - with Fuel	1,326.7	190.0	143.242	3.801
1.5	Western - @ Alliance	799,252.3	116,182.0	145.363	3.857
1.6	Less TCPL Fuel Requirement	(88,416.2)	0.0		
1.	Total Western Canadian Supplies	4,909,494.0	704,546.9	143.507	3.808
2.	Peaking Supplies	39,057.9	11,028.6	282.365	7.492
3.	Ontario Production	730.0	160.8	220.236	5.843
4.	Chicago Supplies	1,839,889.3	296,439.5	161.118	4.275
5.	Delivered Supplies	741,518.2	119,428.4	161.059	4.273
6.	Niagara Supplies	323,693.3	56,430.8	174.334	4.625
7.	Total Supply Costs	7,854,382.8	1,188,034.9	151.258	4.013
	Transportation Costs				
8.1	TCPL - FT - Demand		326,492.4		
8.2	- FT - Commodity	4,110,241.7	22,272.1	5.419	0.144
8.3	- Parkway to CDA		3,238.4		
8.4	- STS - CDA		5,793.8		
8.5	- STS - EDA		4,687.0		
8.6	- Dawn to CDA		10,854.8		
8.7	- Dawn to EDA		22,582.0		
8.8	- Dawn to Iroquois		7,063.3		
8.9	Other Charges		0.0		
8.10	Nova Transmission		7,039.6		
8.11	Alliance Pipeline		36,020.8		
8.12	Vector Pipeline		24,686.2		
8.13	Niagara Falls to Enbridge Parkway DDA		1,783.7		
8.14	Union Parkway to Bram West		2,029.4		
8.	Total Transportation Costs		474,543.5		
9.	Total Before PGVA Adjustment	7,854,382.8	1,662,578.4	211.675	5.616
10.	PGVA Adjustment		(237,242.8)		
11.	Total Purchases & Receipt	7,854,382.8	1,425,335.7	181.470	4.815

Witnesses: J. Denomy
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2015

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
11.	Total Purchases & Receipt	7,854,382.8	1,425,335.7	181.470	4.815
12.	Storage Fluctuation	(77,449.9)	(14,054.8)		
13.	Commodity Cost to Operations	7,776,932.9	1,411,280.8	181.470	
14.	Storage and Transportation Costs		129,603.0		
15.	Gas Cost to Operations	7,776,932.9	1,540,883.9	198.135	5.257
16.	Western T-Service		65,896.7		
17.	Forecasted Gas Costs	7,776,932.9	1,606,780.6	206.609	5.482

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2015

Item #		
1.	Sendout To Operations	7,776,932.9
2.	T-Service Volumes	3,548,753.5
3.	Total Sendout	11,325,686.4
4.1	Residential Sales	4,250,981.3
4.2	Commercial Sales	2,786,769.5
4.3	Industrial Sales	465,634.3
4.4	T-Service	3,532,159.0
4.5	Rate 200 T-Service (Gazifere)	39,042.9
4.6	Rate 200 Sales (Gazifere)	144,827.1
4.7	Company Use	4,197.7
4.8	Unaccounted For (UAF)	78,311.0
4.9	Unbilled Forecast - Sales	22,448.4
4.10	Unbilled Forecast - T-Service	(22,448.4)
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,325,686.4

Witnesses: J. Denomy
D. Small

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2015

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2015	Col. 2 Fiscal 2015 Storage Charges Recovered in Fiscal 2015	Col. 3 Fiscal 2014 Storage Charges Recovered in Fiscal 2015	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2015
	Storage				
1.1	Chatham D	132.3	75.5	57.3	132.8
1.2	Injection	91.4	27.4	63.3	90.8
1.3	Withdrawal	97.6	97.6	0.0	97.6
1.4	Market Based Storage	17,509.8	9,667.6	7,768.7	17,436.3
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	1,634.1	1,634.1	0.0	1,634.1
1.	Total Storage	19,465.1	11,502.2	7,889.4	19,391.5
2.	Total Transportation	67,355.5	37,167.9	29,872.1	67,040.1
	Dehydration				
3.1	Demand	1,012.6	560.9	455.5	1,016.4
3.2	Commodity	170.9	170.9	0.0	170.9
3.	Total Dehydration	1,183.5	731.8	455.5	1,187.3
4.	Total Storage & Other Costs	88,004.1	49,401.9	38,217.0	87,618.9
	Fuel Costs				
5.1	Tecumseh	2,740.4	1,769.1	1,060.5	2,829.7
5.2	Union Storage	734.7	493.2	263.5	756.6
5.3	Union Transportation	11,860.0	11,728.5	144.9	11,873.4
5.	Total Fuel Costs	15,335.2	13,990.8	1,468.9	15,459.7
6.	Unutilized Transportation Costs	26,512.0	26,512.0	0.0	26,512.0
7	Total Storage & Transportation	129,851.3	89,904.7	39,685.9	129,590.6
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				129,590.6

Witnesses: J. Denomy
D. Small

	2014 Budget Peak Day Demand	Column 1	Column 2	Column 3	2015 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,288,088	673,262	3,961,350	Demand	3,303,620	682,952	3,986,572
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(133,995)	(28,705)	(162,700)
3.		3,154,093	644,557	3,798,650		3,169,625	654,247	3,823,872
4.	TCPL FT Capacity	63,468	372,421	435,889	TCPL FT Capacity	63,468	372,421	435,889
5.	TCPL STFT	257,500	-	257,500	TCPL STFT	382,500	-	382,500
6.	TCPL Short Haul	147,587	114,000	261,587	TCPL Short Haul	147,587	114,000	261,587
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,464	80,611	450,075
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	300,354	26,576	326,930
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	132,738	-	132,738	Delivered Service	32,738	-	32,738
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,505	52,753	158,258
12.	Total Supply	3,151,643	646,361	3,798,004	Total Supply	3,176,642	646,361	3,823,004
13.	Sufficency/(Deficiency)	(2,450)	1,804	(646)	Sufficency/(Deficiency)	7,018	(7,886)	(868)

MONTHLY PRICING INFORMATION

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	21 Day Average Empress CGPR	21 Day Average NYMEX	21 Day Average Chicago	21 Day Average US Exchange	$CAD/10^{3}m^3 Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-15	3.8364	4.3948	4.5271	1.0266	
Feb-15	3.8234	4.3826	4.4835	1.0277	
Mar-15	3.7481	4.2961	4.3627	1.0286	
Apr-15	3.5696	4.0931	4.1722	1.0296	
May-15	3.5742	4.1019	4.1795	1.0305	
Jun-15	3.5654	4.1230	4.1679	1.0315	
Jul-15	3.5792	4.1578	4.1781	1.0324	
Aug-15	3.5993	4.1751	4.1848	1.0333	
Sep-15	3.6253	4.1784	4.1870	1.0342	
Oct-15	3.6697	4.2124	4.2950	1.0350	
Nov-15	3.8428	4.2970	4.3761	1.0358	
Dec-15	4.0185	4.4852	4.5940	1.0366	
	3.7043	4.2414	4.3090	1.0318	139.6157
TCPL Fuel Ratio		2.15%			142.6200

(note 1)
Can$/Gj = (NYMEX - Basis) / 1.054615 * US Exchange Rate

(Note 1) $CAD/10^{3}m^3 = $CAD/GJ * 37.69 Mj/m3

21 Day Period 31-Jan-13 to 28-Feb-13

Natural Gas Conversions

mcf times 0.028328 = 10^{3}m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $/10^{3}m^3

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $/10^{3}m^3

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Witnesses: J. Denomy
D. Small

GAS SUPPLY/DEMAND BALANCE

Item #		Col. 1 2015 Budget 10^3m^2	Col. 2 2014 Budget 10^3m^3	Col. 3 2013 Budget 10^3m^3
1.	Total Demand	11,325,686.4	11,232,185.0	11,576,371.2
	Deliveries			
2.1	Western Canadian Supplies	4,909,494.0	4,753,749.3	3,886,090.9
2.2	Peaking/Seasonal	39,057.9	36,068.0	37,998.7
2.3	Ontario Production	730.0	730.0	730.0
2.4	Chicago Supplies	1,839,889.3	1,847,142.8	1,832,109.7
2.5	Delivered Supplies	741,518.2	932,827.1	1,553,462.5
2.6	Niagara Supplies	323,693.3	-	-
2.7	Direct Purchase Delivery	3,558,270.4	3,742,271.6	4,383,689.4
2.8	Storage (Injection)/Withdrawal	(86,966.8)	(80,603.8)	(117,710.0)
2.	Total Delivery	11,325,686.4	11,232,185.0	11,576,371.2

Total Demand includes both System Sales and T-Service Consumption

Witnesses: J. Denomy
D. Small

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2015 UUF Forecast for Preliminary Volumes

1. The 2015 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2015. It is the Company's intent to update the 2015 UAF and Unbilled forecasts as part of the 2015 Rate Adjustment application using the most accurate models as assessed by the inclusion of actual data to 2013.

2. The 2015 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.7% of the total throughput for 2014. To generate preliminary 2015 UAF, 0.7% is applied to the estimated 2015 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2015 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until the annual volumetric update for 2015 and 2016, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2015 Preliminary Forecast for UUF is calculated as follows:

2015 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2015)
– (Forecast unbilled volumes December 2014)
= 78 311 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 311 10^3m^3 + 0 10^3m^3
= 78 311 10^3m^3

Witnesses: H. Sayyan
M. Suarez

COST OF SERVICE
2016 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Normalizing and Other Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	439.5	(100.4)	339.1
3.	Depreciation and amortization expense	303.9	(12.7)	291.2
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	45.5	-	45.5
6.	Operating costs	2,423.3	(113.1)	2,310.2
7.	Income tax expense			(3.0)
8.	Cost of service			2,307.2

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2016 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(100.4)	Operation and Maintenance To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	304.3	304.3	
	Add			
2.	Depreciation and amortization	291.2	291.2	
3.	Accrual based pension and OPEB costs	30.9	30.9	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	323.1	323.1	
6.	Sub-total	627.4	627.4	
	Deduct			
7.	Capital cost allowance	310.1	310.1	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.0	5.0	
10.	Amortization of share/debenture issue expense	3.8	3.8	
11.	Amortization of cumulative eligible capital	4.7	4.7	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site Rest Costs adjustment	58.1	58.1	
14.	Cash based pension and OPEB costs	35.7	35.7	
15.	Total Deduction	464.2	464.2	
16.	Taxable income	163.2	163.2	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	24.5	18.8	43.3
19.	Part VI.1 tax			1.7
20.	Total taxes excluding interest shield			45.0
	Tax shield on interest expense			
21.	Rate base	5,492.0		
22.	Return component of debt	3.30%		
23.	Interest expense	181.1		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(48.0)
26.	Total utility income taxes			(3.0)

Witness: K. Culbert

COST OF SERVICE
2016 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	451.6	(12.1)	439.5
3.	Depreciation	303.1	(0.8)	302.3
4.	Amortization	1.6	-	1.6
5.	Depreciation and amortization	304.7	(0.8)	303.9
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	45.7	(0.2)	45.5
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	45.7	(0.2)	45.5
10.	Interest on long-term debt	176.0	(176.0)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.5	(3.5)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	22.2	(22.2)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	49.0	(49.0)	-
16.	Total operating costs	2,664.9	(241.6)	2,423.3
17.	Current taxes	(10.8)	10.8	-
18.	Deferred taxes	0.7	(0.7)	-
19.	Income tax expense	(10.1)	10.1	-
20.	Cost of service	2,654.8	(231.5)	2,423.3

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2016 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(12.1)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.5
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.7)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.1)
			(12.1)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2016 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
10.	(176.0)	Interest on long-term debt
		Expense of capital.
11.	(3.5)	Amortization of preference share issue costs and debt discount and expense
		Expense of capital.
13.	(22.2)	Interest on short-term debt
		Expense of capital.
14.	(26.8)	Interest due affiliates
		To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
17.	10.8	Income taxes - current
		Income tax expense related to corporate earnings.
18.	(0.7)	Income taxes - deferred
		Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2016 FORECAST YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2016	UCC Carry Forward
1	1,647,857,869	-	-	-	4.00%	(65,914,315)	1,581,943,554
51	2,369,090,344	355,343,030	1,400,000	178,371,515	6.00%	(152,847,712)	2,572,985,663
2	99,879,380	-	(587,655)	(293,828)	6.00%	(5,975,133)	93,316,592
6	9,950	-	-	-	10.00%	(995)	8,955
8	20,862,494	8,073,000	-	4,036,500	20.00%	(4,979,799)	23,955,695
10	15,512,020	5,739,031	(420,613)	2,659,209	30.00%	(5,451,369)	15,379,069
12	32,648,838	31,152,588	-	15,576,294	100.00%	(48,225,132)	15,576,294
12	-	-	-	-	-	-	-
17	25,217	-	-	-	8.00%	(2,017)	23,199
38	3,367,007	1,331,250	(67,100)	632,075	30.00%	(1,199,725)	3,431,432
41	48,683,040	10,769,777	-	5,384,889	25.00%	(13,516,982)	45,935,835
13	16,536,431	270,000	-	135,000	-	(249,000)	16,557,431
3	202,957	-	-	-	5.00%	(10,148)	192,809
45	81,482	-	-	-	45.00%	(36,667)	44,815
50	18,515,892	8,200,000	-	4,100,000	55.00%	(12,438,741)	14,277,152
52	-	-	-	-	100.00%	-	-
Total	4,273,272,919	420,878,676	324,632	210,601,654		(310,847,733)	4,383,628,494

Non-utility and shared asset eliminations	761,685
Utility Federal CCA	(310,086,048)

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 F2016	UCC Carry Forward
1	1,647,857,869	-	-	-	4.00%	(65,914,315)	1,581,943,554
51	2,369,090,344	355,343,030	1,400,000	178,371,515	6.00%	(152,847,712)	2,572,985,663
2	99,879,380	-	(587,655)	(293,828)	6.00%	(5,975,133)	93,316,592
6	9,950	-	-	-	10.00%	(995)	8,955
8	20,862,494	8,073,000	-	4,036,500	20.00%	(4,979,799)	23,955,695
10	15,512,020	5,739,031	(420,613)	2,659,209	30.00%	(5,451,369)	15,379,069
12	32,648,838	31,152,588	-	15,576,294	100.00%	(48,225,132)	15,576,294
12	-	-	-	-	-	-	-
17	25,217	-	-	-	8.00%	(2,017)	23,199
38	3,367,007	1,331,250	(67,100)	632,075	30.00%	(1,199,725)	3,431,432
41	48,683,040	10,769,777	-	5,384,889	25.00%	(13,516,982)	45,935,835
13	16,536,431	270,000	-	135,000	-	(249,000)	16,557,431
3	202,957	-	-	-	5.00%	(10,148)	192,809
45	81,482	-	-	-	45.00%	(36,667)	44,815
50	18,515,892	8,200,000	-	4,100,000	55.00%	(12,438,741)	14,277,152
52	-	-	-	-	100.00%	-	-
Total	4,273,272,919	420,878,676	324,632	210,601,654		(310,847,733)	4,383,628,494

Non-utility and shared asset eliminations	761,685
Utility Provincial CCA and UCC	(310,086,048)

Witness: K. Culbert

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2016 FORECAST AND 2015 FORECAST

		Col. 1	Col. 2	Col. 3
Item No.		2016 Forecast ($Millions)	2015 Forecast ($Millions)	2016 Forecast Over/(Under) 2015 Forecast ($Millions)
1.1	Gas costs charged to operations	1,632.5	1,606.8	25.7
1.2	Operations and maintenance	439.5	428.5	11.0
1.3	Depreciation	303.9	276.6	27.3
1.4	Fixed financing costs	1.9	1.9	-
1.5	Municipal and other taxes	45.5	43.1	2.4
1.0	Total costs and expenses	2,423.3	2,356.9	66.4

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2016 FORECAST AND 2015 FORECAST

Item No.

1.1 Gas costs charged to operations - increase of $25.7 million

The increase in gas costs charged to operations in the 2016 Forecast is primarily due to general service customer growth; partially offset by the continued decline in average use for residential customers. Please refer to Exhibit C5, Tab 2, Schedule 1 for the details of the gas volume budget.

1.2 Operation and maintenance - increase of $11.0 Million

The increase in operation and maintenance costs in the 2016 Forecast is due to higher customer care service charges, higher salaries and wages due to an increase in base salaries, new WAMS hosting and support costs and an increase in outsourced services costs; partially offset by lower pension expense and other post employment benefits (OPEB) as a result of a greater return on assets driven by an expected increase in plan assets.

A comparison of the 2016 Forecast to the 2015 Forecast operation and maintenance costs is provided at Exhibit D1, Tab 3, Schedule 1.

1.3 Depreciation expense – increase of $27.3 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other taxes – increase of $2.4 Million

The increase reflects the inflationary pressure on municipal tax rate, increased municipal taxes in growth for new mains, service connections and for the GTA Leave to Construct Project. The details of municipal taxes are provided at Exhibit D1, Tab 6, Schedule 1.

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2016 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2016
1.	Operations	$ 68,800
2.	Pipeline Integrity & Engineering	40,775
3.	Human Resources and Facilities	22,970
4.	Employee Benefits	26,925
5.	Short Term Incentive Program	22,116
6.	Information Technology	31,680
7.	Regulatory, Public and Government Affairs	21,251
8.	Finance	12,249
9.	Provision for Uncollectibles (Bad Debts)	9,500
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,449
11.	Business Development & Customer Strategy (excluding DSM)	6,506
12.	Legal and Corporate Security	5,491
13.	Energy Supply and Policy	4,449
14.	Non-Departmental	3,752
15.	Capitalization (A&G)	(37,140)
16.	Interest on Security Deposit	2,521
17.	Regulatory Eliminations	(3,295)
18.	Other O&M	240,999
19.	Customer Care/CIS Service Charges	100,426
20.	Pensions and OPEB Costs	30,887
20.	Corporate Cost Allocations (including direct costs)	45,874
21.	Demand Side Management Programs (DSM)	33,458
22.	Subtotal	451,644
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(12,116)
24.	Total Eliminations	(12,116)
25.	Total Net Utility O&M Expense	$ 439,528

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2016 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2016 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 178,977	$ 167,670	$ 11,307	6.7%
2.	Benefits	26,925	25,261	1,664	6.6%
3.	Short Term Incentive Program	22,116	20,700	1,416	6.8%
4.	Employee Training and Development	4,814	4,751	63	1.3%
5.	Materials and Supplies	5,329	5,309	19	0.4%
6.	Outside Services	91,175	83,710	7,466	8.9%
7.	Consulting	5,161	5,082	79	1.6%
8.	Repairs and Maintenance	2,445	2,343	102	4.4%
9.	Fleet	10,678	10,213	465	4.6%
10.	Rents and Leases	7,811	7,338	473	6.4%
11.	Telecommunications	3,912	3,637	275	7.6%
12.	Travel and Other Business Expenses	5,126	5,387	(261)	-4.8%
13.	Memberships	5,247	5,010	237	4.7%
14.	Claims, Damages and Legal Fees	974	863	111	12.9%
15.	Interest on Security Deposits	2,521	780	1,741	223.2%
16.	Provision for Uncollectibles	9,500	9,500	-	0.0%
17.	Legal Fees	2,885	2,700	185	6.9%
18.	Audit Fees	1,671	1,594	77	4.8%
19.	Other	4,990	4,545	445	9.8%
20.	Internal Allocations and Recoveries	(30,145)	(29,900)	(245)	0.8%
21.	Capitalization (A&G)	(37,140)	(37,795)	655	-1.7%
22.	Capitalization	(80,678)	(75,451)	(5,228)	6.9%
23.	Regulatory Eliminations	(3,295)	(4,049)	754	-18.6%
24.	Other O&M	240,999	219,197	21,802	9.9%
25.	Customer Care/CIS Service Charges	100,426	89,444	10,982	12.3%
26.	Pension and OPEB Costs	30,887	42,800	(11,913)	-27.8%
27.	Corporate Cost Allocations (including direct costs)	45,874	45,761	113	0.2%
28.	Demand Side Management Programs (DSM)	33,458	31,588	1,870	5.9%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	451,644	431,519	20,125	4.7%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(12,116)	(13,666)	1,550	-11.3%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(12,116)	(16,394)	4,278	-26.1%
34.	Total Net Utility O&M Expense	$ 439,528	$ 415,125	$ 24,403	5.9%
35.	FTE's	2,361	2,388	-27	-1.1%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2016 Budget Year

Salary Bands	Col. 1 FTE	Col. 2 Total Salaries ($000's)	Col. 3 Average Salary ($000's)
1. Management	152	$ 24,441	$ 160.8
2. Supervisory	1,470	124,163	84.5
3. Unionized	739	48,339	65.4
4. Total	2,361	$ 196,943	$ 83.4

Witnesses: S. Kancharla
R. Lei
S. Trozzi

2016 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 Gas Distribution") during the 2016 Fiscal 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, ie 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.

2. This evidence is provided for the purpose of generating preliminary rate impacts for 2016 to 2018. As set out at Exhibit A2, Tab 3, Schedule 1, the gas costs will be updated for each of those years in annual Rate Adjustment Proceedings.

Gas Supply

3. Enbridge expects to acquire its system gas supply under the following types of contracts during the Fiscal 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.

Witnesses: J. Denomy
D. Small

- 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.
- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn Hub
- Niagara Supply: These supplies are forecasted to be acquired at the Niagara Import/Export point.

Enbridge Gas Distribution 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 2016 gas supply arrangements.

4. The following is Enbridge's forecast of gas supply acquisition during the 2016 fiscal year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	3 922.2	138.4
Ontario Production	0.7	0.0
Peaking	15.9	0.6
Chicago Supply	1 788.2	63.1
Delivered Supply	424.6	15.0
Niagara Supply	1 936.9	68.4
	8 088.5	285.5

Witnesses: J. Denomy
D. Small

<u>Commodity Costs</u>

5. 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.

6. 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.

7. The Company prepared its gas supply forecast based upon a 21-day average of various indices from January 31, 2013 to February 28, 2013 for the 12 months commencing January 1, 2016 (Exhibit D5, Tab 3, Schedule 4) and applied these monthly prices to the 2016 budgeted annual volume gas purchases. For those months where no forecast of prices was available then the forecast for the applicable month in 2015 was used.

8. In an effort to isolate the impact of commodity costs changes the Company removed the impact of the updated price forecast and the April 1, 2013 QRAM prices in a fashion similar to that used in the determination of the 2013 gas cost budget that was filed in EB-2011-0354.

9. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2016 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2016 PGVA. While the Company has prepared the 2016 forecast assuming that it will be acquiring gas in 2016 via traditional transportation paths (ie TCPL, Vector) it has also assumed the

acquisition of gas at the Niagara interconnect on TCPL effective November 1, 2015. Alternate sources of supply remain as a possibility in the future as more pipeline projects are being contemplated. Should any of projects materialize the Company will evaluate them at that time.

<u>Peak Day Coverage</u>

10. In EB -2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed in EB-2011-0354, at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2016 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Based upon the information that was available at the time Enbridge is currently forecasting a design peak day level of 106 451 10^3m^3 (3.8 Bcf) during the winter season of the 2016 fiscal year.

11. Similar to 2015 the Company has chosen to maintain the same level of Peaking Services for 2016 as was forecast for 2015. For purposes of meeting Peak Day Demand in 2016 the Company chose not to rely principally on TCPL STFT service and has looked to other possible solutions in 2016.The driver for this decision is based upon recent events at the National Energy Board (“NEB”). On March 27, 2013 the NEB issued its decision in TransCanada PipeLines Limited (“TransCanada”) Compliance Filing RH-003-2011. Subsequent to that decision TransCanada filed a Review and Variance Application for 2013 to 2017 with the NEB on May 1, 2013 in relation to RH-003-2011. On June 11, 2013 the NEB rendered its decision dismissing in its entirety TransCanada’s Review and Variance Application. On June 12, 2013 TransCanada issued a news release stating their disappointment with the NEB decision and that they were considering all their

options including the potential for an appeal. The June 11, 2013 NEB decision also stated that TransCanada must re-file its Tariff Amendments by June 17, 2013 and that they will be considered as a separate application which will be heard as part of an oral hearing to commence September 3, 2013.

12. The expectation is that the Tariff Amendments TransCanada proposed as a part of its Review and Variance Application will be the subject of the oral hearing mentioned above. The amended Tariff provisions are intended to provide TransCanada the flexibility required to capitalize on market opportunities for discretionary services as they arise. For example, the current Tariff provisions related to posting STFT availability stipulate that TransCanada post available STFT capacity for five banking days during January 1-15 for the Summer Period (April 1 to October 31) and for five banking days during July 1-15 for the Winter Period (November 1 to March 31). For Summer Period monthly blocks of STFT capacity is posted for five banking days during January 16-31 and for the Winter Period monthly blocks of STFT capacity is posted for a five banking days during July 16-31. TransCanada is proposing to change the five banking day requirement to a period to be determined by TransCanada but no less than one day.

13. Planning for STFT in such an environment would be difficult as the availability of this service might not be known until immediately prior to the period for which it is required. In addition the minimum bid floor would most likely be set at a level higher than the FT toll during the periods that the Company would require STFT, that is, during the winter months when demand for this service is high. In order to ensure that it has the assets in place to meet peak day demand in the EDA the Company intends to contract for incremental long haul TCPL FT capacity to the EDA as opposed to relying upon STFT in the winter of 2016. The availability and

cost of STFT in the CDA as well as concerns regarding mainline capacity leads the Company to believe that it may need to rely more on long haul FT capacity in the CDA in the future. The Company intends to continue to monitor the availability of transport to the franchise and to look for alternatives that will provide value to the customers of EGD while still providing safe and reliable service. If alternatives are found then any differences from the cost of those services and those forecasted as part of the 2016 gas cost will be captured in the 2016 Purchased Gas Variance Account (PGVA). A breakdown of the peak day requirement and supply forecast is shown at Exhibit D5, Tab 3 Schedule 3.

14. Based upon the 2016 volumetric forecast and the level of transportation services to meet peak demand in 2016 the Company is not forecasting any cost consequences associated with unutilized transportation capacity. The Company is proposing to provide an update to its 2016 gas supply portfolio prior to the commencement of the 2016 Fiscal Year and as a part of that update the Company will review the level of unutilized transportation costs at that time and update its gas cost forecast for 2016.

<u>Transportation</u>

15. 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 (both long haul and short haul) and Vector Pipeline. The Company has chosen not to renew its contract with the Alliance Pipeline which is set to expire October 31, 2015 as well as two Vector Pipeline contracts totaling 100 000 MMBTU/day also scheduled to expire October 31, 2015. The Company has also assumed 150,000 GJ/day of incremental long haul TCPL FT capacity to the EDA effective November 1, 2015. The inclusion

of the incremental long haul capacity, while assisting with the ability to meet peak day will also lower the overall Dawn discretionary requirement in the summer of 2016. Included in the forecasted supply portfolio effective November 1, 2015 is the acquisition of 200 000 Gj/day of supply at the Niagara interconnect on TCPL. In order to transport that gas from the Niagara import point the Company has assumed the acquisition of 200 000 Gj/day of Niagara Falls to Enbridge Parkway DDA capacity on TCPL. The Company has assumed that effective November 1, 2015 it will contract for 800 000 Gj/day of Union Parkway to Bram West DDA of TCPL capacity (it is expected that 200 000 Gj/day will be assigned to Direct Purchase customers). A copy of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.

16. For the purposes of the 2016 forecast the Company has assumed the assignment of 42,500 Gj/day of TCPL short haul capacity to Direct Purchase customers which was an outcome from the System Reliability consultative (EB-2010-0231) will no longer be required.

17. 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 has assumed that effective November 1, 2015 that it will contract for an incremental 400 000 Gj/day of M12 capacity (it is expected that 200 000 Gj/day will be assigned to Direct

Purchase customers). The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2013 Union tolls.

Storage

18. 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.

19. 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. All three of these contracts have expired and effective April 1, 2010 all of the Company's contracted third party storage is at market based rates

20. During 2016 the Company will be required to issue an RFP for a storage contract(s) that will expire March 31, 2016. For purposes of the 2016 forecast the cost impacts of the current contract(s) are assumed to be continued in the forecast for 2016 gas costs.

Witnesses: J. Denomy
D. Small

Energy Content

21. 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.

Witnesses: J. Denomy
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2016

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	3,180,442.7	451,305.4	141.900	3.765
1.3	Western - @ Nova - TCPL	740,440.0	105,758.5	142.832	3.790
1.4	Western Buy/Sell - with Fuel	1,326.7	192.0	144.697	3.839
1.5	Western - @ Alliance	-	-	0.000	0.000
1.6	Less TCPL Fuel Requirement	(78,218.8)	0.0		
1.	Total Western Canadian Supplies	3,843,990.7	557,255.9	144.968	3.846
2.	Peaking Supplies	15,932.0	5,754.7	361.200	9.583
3.	Ontario Production	730.0	161.9	221.782	5.884
4.	Chicago Supplies	1,788,151.4	291,041.9	162.761	4.318
5.	Delivered Supplies	424,643.2	69,055.2	162.619	4.315
6.	Niagara Supplies	1,936,853.3	324,906.0	167.749	4.451
7.	Total Supply Costs	8,010,300.6	1,248,175.5	155.821	4.134
	Transportation Costs				
8.1	TCPL - FT - Demand		304,383.8		
8.2	- FT - Commodity	3,843,990.7	20,829.4	5.419	0.144
8.3	- Parkway to CDA		3,238.4		
8.4	- STS - CDA		5,793.8		
8.5	- STS - EDA		4,687.0		
8.6	- Dawn to CDA		14,215.1		
8.7	- Dawn to EDA		22,582.0		
8.8	- Dawn to Iroquois		7,063.3		
8.9	Other Charges		0.0		
8.10	Nova Transmission		7,039.6		
8.11	Alliance Pipeline		0.0		
8.12	Vector Pipeline		16,410.7		
8.13	Niagara Falls to Enbridge Parkway DDA		10,701.1		
8.14	Union Parkway to Bram West		12,176.4		
8.	Total Transportation Costs		429,120.6		
9.	Total Before PGVA Adjustment	8,010,300.6	1,677,296.1	209.392	5.556
10.	PGVA Adjustment		(206,792.6)		
11.	Total Purchases & Receipt	8,010,300.6	1,470,503.5	183.577	4.871

Witnesses: J. Denomy
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2016

Item #		Col. 1 10^3m^3	Col. 2 \$(000)	Col. 3 \$/10^3m^3 (Col.2 / Col.1)	Col. 4 \$/GJ (Col.3 / 37.69)
11.	Total Purchases & Receipt	8,010,300.6	1,470,503.5	183.577	4.871
12.	Storage Fluctuation	(36,989.4)	(6,790.4)		
13.	Commodity Cost to Operations	7,973,311.2	1,463,713.1	183.577	
14.	Storage and Transportation Costs		105,616.0		
15.	Gas Cost to Operations	7,973,311.2	1,569,329.1	196.823	5.222
16.	Western T-Service		63,059.3		
17.	Forecasted Gas Costs	7,973,311.2	1,632,388.4	204.732	5.432

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2016

Item #		
1.	Sendout To Operations	7,973,311.2
2.	T-Service Volumes	3,451,949.0
3.	Total Sendout	11,425,260.2
4.1	Residential Sales	4,341,770.3
4.2	Commercial Sales	2,893,582.0
4.3	Industrial Sales	477,265.4
4.4	T-Service	3,419,807.5
4.5	Rate 200 T-Service (Gazifere)	39,042.9
4.6	Rate 200 Sales (Gazifere)	146,831.8
4.7	Company Use	4,197.7
4.8	Unaccounted For (UAF)	78,999.0
4.9	Unbilled Forecast - Sales	6,901.4
4.10	Unbilled Forecast - T-Service	(6,901.4)
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,425,260.2

Witnesses: J. Denomy
D. Small

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2016

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2016	Col. 2 Fiscal 2016 Storage Charges Recovered in Fiscal 2016	Col. 3 Fiscal 2015 Storage Charges Recovered in Fiscal 2016	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2016
	Storage				
1.1	Chatham D	132.3	75.0	56.8	131.8
1.2	Injection	70.4	21.1	64.0	85.1
1.3	Withdrawal	85.9	85.9	0.0	85.9
1.4	Market Based Storage	17,778.2	9,755.5	7,842.2	17,597.7
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	2,187.4	2,187.4	0.0	2,187.4
1.	Total Storage	20,254.2	12,124.9	7,963.0	20,087.9
2.	Total Transportation	72,119.5	39,674.5	30,187.5	69,862.1
	Dehydration				
3.1	Demand	1,012.6	557.0	451.7	1,008.7
3.2	Commodity	179.3	179.3	0.0	179.3
3.	Total Dehydration	1,191.8	736.3	451.7	1,188.0
4.	Total Storage & Other Costs	93,565.5	52,535.8	38,602.2	91,138.0
	Fuel Costs				
5.1	Tecumseh	2,830.8	1,828.3	971.3	2,799.6
5.2	Union Storage	592.9	406.8	241.6	648.3
5.3	Union Transportation	11,030.2	10,898.7	131.5	11,030.2
5.	Total Fuel Costs	14,453.8	13,133.7	1,344.4	14,478.1
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	108,019.3	65,669.5	39,946.6	105,616.0
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				105,616.0

Witnesses: J. Denomy
D. Small

	2015 Budget Peak Day Demand	Column 1	Column 2	Column 3	2016 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,303,620	682,952	3,986,572	Demand	3,319,312	692,836	4,012,148
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(133,995)	(28,705)	(162,700)
3.		3,169,625	654,247	3,823,872		3,185,316	664,131	3,849,448
4.	TCPL FT Capacity	63,468	372,421	435,889	TCPL FT Capacity	63,468	347,421	410,889
5.	TCPL STFT	382,500	-	382,500	TCPL STFT	100,000	-	100,000
6.	TCPL Short Haul	147,587	114,000	261,587	TCPL Short Haul	149,818	154,000	303,818
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,464	80,611	450,075
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	300,354	26,576	326,930
9.	Niagara Deliveries	-	-	-	Niagara Deliveries	200,000	-	200,000
10.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,975,027	-	1,975,027
11.	Delivered Service	32,738	-	32,738	Delivered Service	32,738	-	32,738
12.	Peaking Service	105,505	52,753	158,258	Peaking Service	-	52,753	52,753
13.	Total Supply	3,176,642	646,361	3,823,004	Total Supply	3,190,869	661,361	3,852,231
	Sufficency/(Deficiency)	7,018	(7,886)	(868)	Sufficency/(Deficiency)	5,553	(2,770)	2,783

Witnesses: J. Denomy
D. Small

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/$10^3m^3$ Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-16	4.1435	4.5872	4.7165	1.0373	
Feb-16	4.1261	4.5668	4.6618	1.0529	
Mar-15	3.7481	4.2961	4.3627	1.0286	
Apr-15	3.5696	4.0931	4.1722	1.0296	
May-15	3.5742	4.1019	4.1795	1.0305	
Jun-15	3.5654	4.1230	4.1679	1.0315	
Jul-15	3.5792	4.1578	4.1781	1.0324	
Aug-15	3.5993	4.1751	4.1848	1.0333	
Sep-15	3.6253	4.1784	4.1870	1.0342	
Oct-15	3.6697	4.2124	4.2950	1.0350	
Nov-15	3.8428	4.2970	4.3761	1.0358	
Dec-15	4.0185	4.4852	4.5940	1.0366	
	3.7551	4.2728	4.3396	1.0348	141.5311
TCPL Fuel Ratio		2.15%			144.5765

(note 1)
Can$/Gj = (NYMEX - Basis) / 1.054615 * US Exchange Rate

(Note 1) $CAD/$10^3m^3$ = $CAD/GJ * 37.69 Mj/m3

21 Day Period **31-Jan-13** **to** **28-Feb-13**

Natural Gas Conversions

mcf times 0.028328 = 10^3m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $/$10^3m^3$

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/$m^3$ = $/$10^3m^3$

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Witnesses: J. Denomy
D. Small

GAS SUPPLY/DEMAND BALANCE

Item #		Col. 1 2016 Budget 10^3m^2	Col. 2 2015 Budget 10^3m^2	Col. 3 2014 Budget 10^3m^3
1.	Total Demand	11,425,260.2	11,325,686.4	11,232,185.0
	Deliveries			
2.1	Western Canadian Supplies	3,843,990.7	4,909,494.0	4,753,749.3
2.2	Peaking/Seasonal	15,932.0	39,057.9	36,068.0
2.3	Ontario Production	730.0	730.0	730.0
2.4	Chicago Supplies	1,788,151.4	1,839,889.3	1,847,142.8
2.5	Delivered Supplies	424,643.2	741,518.2	932,827.1
2.6	Niagara Supplies	1,936,853.3	323,693.3	-
2.7	Direct Purchase Delivery	3,480,796.4	3,558,270.4	3,742,271.6
2.8	Storage (Injection)/Withdrawal	(65,836.6)	(86,966.8)	(80,603.8)
2.	Total Delivery	11,425,260.4	11,325,686.4	11,232,185.0

Total Demand includes both System Sales and T-Service Consumption

Witnesses: J. Denomy
D. Small

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2016 UUF Forecast for Preliminary Volumes

1. The 2016 UUF forecast is provided for the purpose of generating preliminary rate impacts for 2016, 2017 and 2018. It is the Company's intent to update the 2016 to 2018 UAF and Unbilled forecasts as part of the 2016 to 2018 Rate Adjustment applications using the most accurate models as assessed by the inclusion of actual data to 2014, 2015 and 2016.

2. This 2016 UAF forecast draws from the results of the UAF methodology applied for the 2014 Test Year. The 2014 UAF forecast represents 0.7% of the total throughput for 2014. To generate preliminary 2016 UAF, 0.7% is applied to the estimated 2016 volumes. Please see Exhibit D3, Tab 4, Schedule 1 for full details on the methodology employed.

3. The 2016 change in unbilled volumes is assumed to be zero. Unbilled volumes are highly correlated with the level of degree days. As degree days are held constant at the 2014 level until the annual volumetric update for 2015 and 2016, there is no change in unbilled volumes. Please see Exhibit D3, Tab 4, Schedule 1 for more detail.

4. The 2016 Preliminary Forecast for UUF is calculated as follows:

2016 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2016)
– (Forecast unbilled volumes December 2015)
= 78 999 10^3m^3 + (704 606 10^3m^3 – 704 606 10^3m^3)
= 78 999 10^3m^3 + 0 10^3m^3
= 78 999 10^3m^3

Witnesses: H. Sayyan
M. Suarez

COST OF SERVICE
2017 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Normalizing and Other Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	450.5	(104.4)	346.1
3.	Depreciation and amortization expense	313.4	(12.7)	300.7
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	47.9	-	47.9
6.	Operating costs	2,446.2	(117.1)	2,329.1
7.	Income tax expense			1.3
8.	Cost of service			2,330.4

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(104.4)	Operation and Maintenance To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	295.2	295.2	
	Add			
2.	Depreciation and amortization	300.7	300.7	
3.	Accrual based pension and OPEB costs	28.5	28.5	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	330.2	330.2	
6.	Sub-total	625.4	625.4	
	Deduct			
7.	Capital cost allowance	293.2	293.2	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	3.9	3.9	
11.	Amortization of cumulative eligible capital	4.3	4.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	53.1	53.1	
14.	Cash based pension and OPEB costs	32.2	32.2	
15.	Total Deduction	439.0	439.0	
16.	Taxable income	186.4	186.4	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	28.0	21.4	49.4
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			51.3
	Tax shield on interest expense			
21.	Rate base	5,716.9		
22.	Return component of debt	3.30%		
23.	Interest expense	188.5		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(50.0)
26.	Total utility income taxes			1.3

Witness: K. Culbert

COST OF SERVICE
2017 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	463.0	(12.5)	450.5
3.	Depreciation	312.6	(0.8)	311.8
4.	Amortization	1.6	-	1.6
5.	Depreciation and amortization	314.2	(0.8)	313.4
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	48.1	(0.2)	47.9
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	48.1	(0.2)	47.9
10.	Interest on long-term debt	176.0	(176.0)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.5	(3.5)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	22.2	(22.2)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	49.0	(49.0)	-
16.	Total operating costs	2,688.2	(242.0)	2,446.2
17.	Current taxes	(10.8)	10.8	-
18.	Deferred taxes	0.7	(0.7)	-
19.	Income tax expense	(10.1)	10.1	-
20.	Cost of service	2,678.1	(231.9)	2,446.2

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(12.5)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.6
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.5)
			(12.5)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(176.0)	Interest on long-term debt Expense of capital.
13.	(3.5)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(22.2)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	10.8	Income taxes - current Income tax expense related to corporate earnings.
20.	(0.7)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2017 FORECAST YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,572,985,662	347,950,400	-	173,975,200	6.00%	(164,817,652)	2,756,118,411
2	93,316,592	-	(337,655)	(168,828)	6.00%	(5,588,866)	87,390,071
6	8,955	-	-	-	10.00%	(896)	8,060
8	23,955,695	8,073,000	-	4,036,500	20.00%	(5,598,439)	26,430,256
10	15,379,069	5,739,031	(420,613)	2,659,209	30.00%	(5,411,483)	15,286,004
12	15,576,294	19,300,000	-	9,650,000	100.00%	(25,226,294)	9,650,000
12	-	-	-	-	-	-	-
17	23,199	-	-	-	8.00%	(1,856)	21,343
38	3,431,432	1,331,250	(67,100)	632,075	30.00%	(1,219,052)	3,476,530
41	45,935,835	7,813,842	-	3,906,921	25.00%	(12,460,689)	41,288,988
13	16,557,431	270,000	-	135,000	-	(249,000)	16,578,431
3	192,809	-	-	-	5.00%	(9,641)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	14,277,151	8,200,000	-	4,100,000	55.00%	(10,107,433)	12,369,718
52	-	-	-	-	100.00%	-	-
Total	4,383,628,494	398,677,523	(825,368)	198,926,078		(293,989,209)	4,487,491,440

Non-utility and shared asset eliminations	758,942
Utility Federal CCA	(293,230,267)

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 F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,572,985,662	347,950,400	-	173,975,200	6.00%	(164,817,652)	2,756,118,411
2	93,316,592	-	(337,655)	(168,828)	6.00%	(5,588,866)	87,390,071
6	8,955	-	-	-	10.00%	(896)	8,060
8	23,955,695	8,073,000	-	4,036,500	20.00%	(5,598,439)	26,430,256
10	15,379,069	5,739,031	(420,613)	2,659,209	30.00%	(5,411,483)	15,286,004
12	15,576,294	19,300,000	-	9,650,000	100.00%	(25,226,294)	9,650,000
12	-	-	-	-	-	-	-
17	23,199	-	-	-	8.00%	(1,856)	21,343
38	3,431,432	1,331,250	(67,100)	632,075	30.00%	(1,219,052)	3,476,530
41	45,935,835	7,813,842	-	3,906,921	25.00%	(12,460,689)	41,288,988
13	16,557,431	270,000	-	135,000	-	(249,000)	16,578,431
3	192,809	-	-	-	5.00%	(9,640)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	14,277,151	8,200,000	-	4,100,000	55.00%	(10,107,433)	12,369,718
52	-	-	-	-	100.00%	-	-
Total	4,383,628,494	398,677,523	(825,368)	198,926,078		(293,989,209)	4,487,491,440

Non-utility and shared asset eliminations	758,942
Utility Provincial CCA and UCC	(293,230,267)

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2017 FORECAST AND 2016 FORECAST

		Col. 1	Col. 2	Col. 3
Item No.		2017 Forecast ($Millions)	2016 Forecast ($Millions)	2017 Forecast Over/(Under) 2016 Forecast ($Millions)
1.1	Gas costs charged to operations	1,632.5	1,632.5	-
1.2	Operations and maintenance	450.5	439.5	11.0
1.3	Depreciation	313.4	303.9	9.5
1.4	Fixed financing costs	1.9	1.9	-
1.5	Municipal and other taxes	47.9	45.5	2.4
1.0	Total costs and expenses	2,446.2	2,423.3	22.9

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2017 FORECAST AND 2016 FORECAST

Item No.

1.1 Gas costs charged to operations – immaterial change

1.2 Operation and maintenance - increase of $11.0 Million

The increase in operation and maintenance costs in the 2017 Forecast from 2016 forecast is primarily due to applying average annual growth rate for the "Other O&M" and RCAM costs from 2013 to 2016 and the inflationary pressures for the 2016 DSM forecast.

1.3 Depreciation expense – increase of $9.5 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other taxes – increase of $2.4 Million

The increase reflects the average rate of change on municipal tax rate.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2017 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2017
1.	Operations	$ 70,947
2.	Pipeline Integrity & Engineering	42,047
3.	Human Resources and Facilities	23,687
4.	Employee Benefits	27,765
5.	Short Term Incentive Program	22,806
6.	Information Technology	32,668
7.	Regulatory, Public and Government Affairs	21,914
8.	Finance	12,631
9.	Provision for Uncollectibles (Bad Debts)	9,796
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,526
11.	Business Development & Customer Strategy (excluding DSM)	6,709
12.	Legal and Corporate Security	5,662
13.	Energy Supply and Policy	4,588
14.	Non-Departmental	3,869
15.	Capitalization (A&G)	(38,299)
16.	Interest on Security Deposit	2,599
17.	Regulatory Eliminations	(3,398)
18.	Other O&M	248,518
19.	Customer Care/CIS Service Charges	104,400
20.	Pensions and OPEB Costs	28,500
20.	Corporate Cost Allocations (including direct costs)	44,650
21.	Demand Side Management Programs (DSM)	34,200
22.	Subtotal	460,268
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(9,818)
24.	Total Eliminations	(9,818)
25.	Total Net Utility O&M Expense	$ 450,450

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2017 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2017 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 183,113	$ 166,355	$ 16,758	10.1%
2.	Benefits	27,765	25,261	2,505	9.9%
3.	Short Term Incentive Program	22,806	20,700	2,106	10.2%
4.	Employee Training and Development	4,964	4,751	214	4.5%
5.	Materials and Supplies	5,495	5,309	186	3.5%
6.	Outside Services	94,020	83,710	10,310	12.3%
7.	Consulting	5,322	5,082	240	4.7%
8.	Repairs and Maintenance	2,522	2,343	179	7.6%
9.	Fleet	11,011	10,213	799	7.8%
10.	Rents and Leases	8,055	7,338	717	9.8%
11.	Telecommunications	4,034	3,637	397	10.9%
12.	Travel and Other Business Expenses	5,286	5,387	(101)	-1.9%
13.	Memberships	5,411	5,010	401	8.0%
14.	Claims, Damages and Legal Fees	1,004	863	142	16.4%
15.	Interest on Security Deposits	2,599	780	1,819	233.3%
16.	Provision for Uncollectibles	9,796	9,500	296	3.1%
17.	Legal Fees	2,975	2,700	275	10.2%
18.	Audit Fees	1,723	1,594	129	8.1%
19.	Other	5,146	4,545	601	13.2%
20.	Internal Allocations and Recoveries	(31,086)	(29,900)	(1,186)	4.0%
21.	Capitalization (A&G)	(38,299)	(37,795)	(503)	1.3%
22.	Capitalization	(81,748)	(74,136)	(7,612)	10.3%
23.	Regulatory Eliminations	(3,398)	(4,049)	652	-16.1%
24.	Other O&M	248,518	219,197	29,321	13.4%
25.	Customer Care/CIS Service Charges	104,400	89,444	14,956	16.7%
26.	Pension and OPEB Costs	28,500	42,800	(14,300)	-33.4%
27.	Corporate Cost Allocations (including direct costs)	44,650	45,761	(1,111)	-2.4%
28.	Demand Side Management Programs (DSM)	34,200	31,588	2,612	8.3%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	460,268	431,519	28,749	6.7%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(9,818)	(13,666)	3,848	-28.2%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(9,818)	(16,394)	6,576	-40.1%
34.	Total Net Utility O&M Expense	$ 450,450	$ 415,125	$ 35,325	8.5%
35.	FTE's	2,361	2,388	-27	-1.1%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES
2017 Budget Year

	Col. 1	Col. 2	Col. 3
Salary Bands	FTE	Total Salaries ($000's)	Average Salary ($000's)
1. Management	152	$ 25,204	$ 165.8
2. Supervisory	1,470	128,038	87.1
3. Unionized	739	49,848	67.5
4. Total	2,361	$ 203,089	$ 86.0

Witnesses: S. Kancharla
R. Lei
S. Trozzi

COST OF SERVICE
2018 FORECAST YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	461.8	(108.5)	353.3
3.	Depreciation and amortization expense	322.1	(12.7)	309.4
4.	Fixed financing costs	1.9	-	1.9
5.	Municipal and other taxes	50.4	-	50.4
6.	Operating costs	2,468.7	(121.2)	2,347.5
7.	Income tax expense			8.7
8.	Cost of service			2,356.2

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
2.	(108.5)	Operation and Maintenance To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.
3.	(12.7)	Depreciation and Amortization Expense To remove Customer Care and CIS impacts determined in accordance with the calculation process approved by the Board in EB-2011-0226.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 FORECAST YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	286.6	286.6	
	Add			
2.	Depreciation and amortization	309.4	309.4	
3.	Accrual based pension and OPEB costs	26.2	26.2	
4.	Other non-deductible items	1.0	1.0	
5.	Total Add Back	336.6	336.6	
6.	Sub-total	623.2	623.2	
	Deduct			
7.	Capital cost allowance	293.8	293.8	
8.	Items capitalized for regulatory purposes	46.6	46.6	
9.	Deduction for "grossed up" Part VI.1 tax	5.6	5.6	
10.	Amortization of share/debenture issue expense	4.0	4.0	
11.	Amortization of cumulative eligible capital	4.0	4.0	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Rest Costs adjustment	17.4	17.4	
14.	Cash based pension and OPEB costs	29.8	29.8	
15.	Total Deduction	401.3	401.3	
16.	Taxable income	221.9	221.9	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	33.3	25.5	58.8
19.	Part VI.1 tax			1.9
20.	Total taxes excluding interest shield			60.7
	Tax shield on interest expense			
21.	Rate base	5,899.1		
22.	Return component of debt	3.33%		
23.	Interest expense	196.4		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(52.0)
26.	Total utility income taxes			8.7

COST OF SERVICE
2018 FORECAST YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,632.5	-	1,632.5
2.	Operation and maintenance	474.7	(12.9)	461.8
3.	Depreciation	321.3	(0.8)	320.5
4.	Amortization	1.6	-	1.6
5.	Depreciation and amortization	322.9	(0.8)	322.1
6.	Fixed financing costs	1.9	-	1.9
7.	Municipal and other taxes	50.6	(0.2)	50.4
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	50.6	(0.2)	50.4
10.	Interest on long-term debt	176.0	(176.0)	-
11.	Amortization of preference share issue costs and debt discount and expense	3.5	(3.5)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	22.2	(22.2)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	49.0	(49.0)	-
16.	Total operating costs	2,711.1	(242.4)	2,468.7
17.	Current taxes	(10.8)	10.8	-
18.	Deferred taxes	0.7	(0.7)	-
19.	Income tax expense	(10.1)	10.1	-
20.	Cost of service	2,701.0	(232.3)	2,468.7

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(12.9)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	2.7
		To eliminate donations (EBRO 490).	(0.9)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.9)
			(12.9)
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 FORECAST YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(176.0)	Interest on long-term debt Expense of capital.
13.	(3.5)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(22.2)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	10.8	Income taxes - current Income tax expense related to corporate earnings.
20.	(0.7)	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2018 FORECAST YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2017	UCC Carry Forward
1	1,518,665,812	-	-	-	4.00%	(60,746,633)	1,457,919,179
51	2,756,118,411	352,699,649	-	176,349,825	6.00%	(175,948,094)	2,932,869,966
2	87,390,071	-	(337,655)	(168,828)	6.00%	(5,233,275)	81,819,141
6	8,060	-	-	-	10.00%	(806)	7,254
8	26,430,256	8,073,000	-	4,036,500	20.00%	(6,093,351)	28,409,905
10	15,286,004	5,739,031	(420,613)	2,659,209	30.00%	(5,383,564)	15,220,858
12	9,650,000	19,300,000	-	9,650,000	100.00%	(19,300,000)	9,650,000
12	-	-	-	-	-	-	-
17	21,343	-	-	-	8.00%	(1,708)	19,636
38	3,476,530	1,331,250	(67,100)	632,075	30.00%	(1,232,582)	3,508,098
41	41,288,988	7,813,842	-	3,906,921	25.00%	(11,298,977)	37,803,853
13	16,578,431	270,000	-	135,000	-	(249,000)	16,599,431
3	183,169	-	-	-	5.00%	(9,158)	174,010
45	24,648	-	-	-	45.00%	(11,092)	13,557
50	12,369,718	8,200,000	-	4,100,000	55.00%	(9,058,345)	11,511,373
52	-	-	-	-	100.00%	-	-
Total	4,487,491,440	403,426,772	(825,368)	201,300,702		(294,566,584)	4,595,526,260

Non-utility and shared asset eliminations	756,512
Utility Federal CCA	(293,810,072)

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 F2017	UCC Carry Forward
1	1,518,665,812	-	-	-	4.00%	(60,746,633)	1,457,919,179
51	2,756,118,411	352,699,649	-	176,349,825	6.00%	(175,948,094)	2,932,869,966
2	87,390,071	-	(337,655)	(168,828)	6.00%	(5,233,275)	81,819,141
6	8,060	-	-	-	10.00%	(806)	7,254
8	26,430,256	8,073,000	-	4,036,500	20.00%	(6,093,351)	28,409,905
10	15,286,004	5,739,031	(420,613)	2,659,209	30.00%	(5,383,564)	15,220,858
12	9,650,000	19,300,000	-	9,650,000	100.00%	(19,300,000)	9,650,000
12	-	-	-	-	-	-	-
17	21,343	-	-	-	8.00%	(1,708)	19,636
38	3,476,530	1,331,250	(67,100)	632,075	30.00%	(1,232,582)	3,508,098
41	41,288,988	7,813,842	-	3,906,921	25.00%	(11,298,977)	37,803,853
13	16,578,431	270,000	-	135,000	-	(249,000)	16,599,431
3	183,169	-	-	-	5.00%	(9,158)	174,010
45	24,648	-	-	-	45.00%	(11,092)	13,557
50	12,369,718	8,200,000	-	4,100,000	55.00%	(9,058,345)	11,511,373
52	-	-	-	-	100.00%	-	-
Total	4,487,491,440	403,426,772	(825,368)	201,300,702		(294,566,584)	4,595,526,260

Non-utility and shared asset eliminations	756,512
Utility Provincial CCA and UCC	(293,810,072)

COST COMPARISON OF UTILITY
OPERATING COSTS AND EXPENSES
2018 FORECAST AND 2017 FORECAST

Item No.		Col. 1 2018 Forecast ($Millions)	Col. 2 2017 Forecast ($Millions)	Col. 3 2018 Forecast Over/(Under) 2017 Forecast ($Millions)
1.1	Gas costs charged to operations	1,632.5	1,632.5	-
1.2	Operations and maintenance	461.8	450.5	11.3
1.3	Depreciation	322.1	313.4	8.7
1.4	Fixed financing costs	1.9	1.9	-
1.5	Municipal and other taxes	50.4	47.9	2.5
1.0	Total costs and expenses	2,468.7	2,446.2	22.5

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2018 FORECAST AND 2017 FORECAST

Item No.

1.1 Gas costs charged to operations – immaterial change

1.2 Operation and maintenance - increase of $11.3 Million

The increase in operation and maintenance costs in the 2018 Forecast from 2017 forecast is primarily due to applying average annual growth rate for the “Other O&M” and RCAM costs from 2013 to 2016 and the inflationary pressures for the 2017 DSM forecast.

1.3 Depreciation expense – increase of $8.7 Million

The increase in depreciation expense is mainly due to higher depreciable PP&E resulting from the annual capital expenditures.

1.4 Fixed financing costs – immaterial change

1.5 Municipal and other taxes – increase of $2.5 Million

The increase reflects the average rate of change on municipal tax rate.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2018 Forecast Year

Line No.	Particulars ($ 000's)	Budget 2018
1.	Operations	$ 73,160
2.	Pipeline Integrity & Engineering	43,359
3.	Human Resources and Facilities	24,426
4.	Employee Benefits	28,632
5.	Short Term Incentive Program	23,518
6.	Information Technology	33,688
7.	Regulatory, Public and Government Affairs	22,598
8.	Finance	13,025
9.	Provision for Uncollectibles (Bad Debts)	10,102
10.	Customer Care (Exclude CC/CIS and Bad Debts)	2,604
11.	Business Development & Customer Strategy (excluding DSM)	6,919
12.	Legal and Corporate Security	5,839
13.	Energy Supply and Policy	4,731
14.	Non-Departmental	3,989
15.	Capitalization (A&G)	(39,494)
16.	Interest on Security Deposit	2,681
17.	Regulatory Eliminations	(3,504)
18.	Other O&M	256,272
19.	Customer Care/CIS Service Charges	108,500
20.	Pensions and OPEB Costs	26,200
20.	Corporate Cost Allocations (including direct costs)	46,043
21.	Demand Side Management Programs (DSM)	34,900
22.	Subtotal	471,915
	Other Regulatory Eliminations	
23.	To eliminate Corporate Cost Allocations above RCAM	(10,151)
24.	Total Eliminations	(10,151)
25.	Total Net Utility O&M Expense	$ 461,764

Notes:
1) Departmental O&M costs are net of capitalization.
2) Budget years have been restated based on the 2013 organization structure.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2018 Forecast Year vs. 2013 Board Approved

Line No.	Particulars ($000's)	Budget 2018 (a)	Board Approved 2013 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$188,826	$ 166,355	$ 22,472	13.5%
2.	Benefits	28,632	25,261	3,371	13.3%
3.	Short Term Incentive Program	23,518	20,700	2,817	13.6%
4.	Employee Training and Development	5,119	4,751	368	7.8%
5.	Materials and Supplies	5,666	5,309	357	6.7%
6.	Outside Services	96,953	83,710	13,244	15.8%
7.	Consulting	5,488	5,082	406	8.0%
8.	Repairs and Maintenance	2,600	2,343	257	11.0%
9.	Fleet	11,355	10,213	1,142	11.2%
10.	Rents and Leases	8,306	7,338	968	13.2%
11.	Telecommunications	4,160	3,637	523	14.4%
12.	Travel and Other Business Expenses	5,451	5,387	64	1.2%
13.	Memberships	5,579	5,010	570	11.4%
14.	Claims, Damages and Legal Fees	1,036	863	173	20.1%
15.	Interest on Security Deposits	2,681	780	1,901	243.7%
16.	Provision for Uncollectibles	10,102	9,500	602	6.3%
17.	Legal Fees	3,068	2,700	368	13.6%
18.	Audit Fees	1,777	1,594	183	11.5%
19.	Other	5,307	4,545	762	16.8%
20.	Internal Allocations and Recoveries	(32,056)	(29,900)	(2,155)	7.2%
21.	Capitalization (A&G)	(39,494)	(37,795)	(1,698)	4.5%
22.	Capitalization	(84,299)	(74,136)	(10,163)	13.7%
23.	Regulatory Eliminations	(3,504)	(4,049)	546	-13.5%
24.	Other O&M	256,272	219,197	37,075	16.9%
25.	Customer Care/CIS Service Charges	108,500	89,444	19,056	21.3%
26.	Pension and OPEB Costs	26,200	42,800	(16,600)	-38.8%
27.	Corporate Cost Allocations (including direct costs)	46,043	45,761	282	0.6%
28.	Demand Side Management Programs (DSM)	34,900	31,588	3,312	10.5%
29.	Conservation Services	-	2,728	(2,728)	-100.0%
30.	Subtotal	471,915	431,519	40,396	9.4%
	Other Regulatory Eliminations				
31.	To eliminate Corporate Cost Allocations above RCAM	(10,151)	(13,666)	3,515	-25.7%
32.	To eliminate Conservation Services	-	(2,728)	2,728	-100.0%
33.	Total Eliminations	(10,151)	(16,394)	6,243	-38.1%
34.	Total Net Utility O&M Expense	$461,764	$ 415,125	$ 46,639	11.2%
35.	FTE's	2,361	2,388	-27	-1.1%

Witnesses: S. Kancharla
R. Lei

FTE and SALARIES & WAGES

2018 Budget Year

	Col. 1	Col. 2	Col. 3
Salary Bands	FTE	Total Salaries ($000's)	Average Salary ($000's)
1. Management	152	$ 25,990	$ 171.0
2. Supervisory	1,470	132,033	89.8
3. Unionized	739	51,403	69.6
4. Total	2,361	$ 209,426	$ 88.7

Witnesses: S. Kancharla
R. Lei
S. Trozzi