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March 24, 2014

VIA RESS, EMAIL and COURIER

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

**Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
New and Updated Exhibits**

Further to Enbridge Gas Distribution's filing of March 21, 2014, enclosed please find new and updated exhibits as follows:

Exhibit D1, Tab 8, Schedule 1, updates to pages 2 and 3 (indicated with a /u) and page 30 only. All other pages are being re-filed as the page numbers changed.
Exhibit D1, Tab 8, Schedule 2, (updated);
Exhibit D1, Tab 8, Schedule 2, Appendix A (new);
Exhibit D1, Tab 8, Schedule 7 (new);
Exhibit M1, Tab 1, Schedules 1 to 6 (new)
Exhibit J5.10 (updated); and
Exhibit J9.4

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

Yours truly,

(Original Signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

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"),

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>

2. The Company has reviewed the existing required and potential requirement for deferral and variance accounts during the 2014-2018 rate making period and 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, RPMVA, and GTAITCRRDA with separate /u written evidence 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"),

Witnesses: K. Culbert
D. Small

2014-2018 Ontario Hearing Costs Variance Account ("OHCVA"),
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"),
2017-2018 Relocation Mains Variance Account ("RLMVA"),
2017-2018 Replacement Mains Variance Account ("RPMVA") and
2015-2018 Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA"). /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.

Witnesses: K. Culbert
D. Small

2014 Design Day Criteria Transportation Deferral Account ("2014 DDCTDA")

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.

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.

2014-2018 Storage and Transportation Deferral Account ("2014-2018 S&TDA")

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.

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 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.

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

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.

2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")

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.

2014-2018 Manufactured Gas Plant Deferral Account ("2014-2018 MGPDA")

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

Witnesses: K. Culbert
D. Small

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.

Witnesses: K. Culbert
D. Small

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.

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

2015-2018 GREATER TORONTO AREA INCREMENTAL TRANSMISSION CAPITAL REVENUE REQUIREMENT DEFERRAL ACCOUNT (“GTAITCRRDA”)

88. In the Decision in the Greater Toronto Area (“GTA”) Leave-to-Construct (LTC) proceeding, EB-2012-0451, the Board ordered the Company to create a deferral account to track the revenue requirement impact in relation to $55 million in incremental capital spending which resulted from the upsizing of the transmission component of Segment A within the GTA project. In accordance with the Decision, the Company filed a Draft Accounting Order seeking approval to establish the GTAITCRRDA. The Accounting Order was subsequently approved on March 11, 2014. The GTAITCRRDA will be required in the event that at the time Segment A is put into service, there is either no transportation customer(s), or no ability for transportation customer(s) to utilize Segment A of the pipeline. Any revenue requirement amount recorded in the account will represent revenue to be collected from transportation customers once they begin taking service on Segment A under Rate 332.

89. Further details of the GTAITCRRDA can be found in evidence at Exhibit D1, Tab 8, Schedule 7.

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 2015 to 2018 within this rate application.

2. The GTA project details and rationale were filed within EGD's EB-2012-0451 Leave to Construct ("LTC") application which was approved by Board Decision on January 30, 2014. Attached as Appendix A to this Exhibit, EGD has provided the updated forecast total GTA project cost allowed revenue amounts for 2015-2018 (excluding gas cost forecasts and impacts), relative to the LTC decision, which are also embedded within EGD's overall Allowed Revenue amounts for those years, as updated in Impact Statement Number 1.

3. EGD is proposing that this variance account will be used to report any variance between the forecast Allowed Revenue amounts in Appendix A, and the eventual actual Allowed Revenue amounts. The Company proposes that the annual Allowed Revenue variance, for each of the fiscal years 2015 through 2018, be recognized within the variance account with an offsetting annual entry through revenue. The annual variance is proposed to be cleared along with any and all other deferral or variance accounts for the subject year.

4. The scale of the GTA project could potentially result in normal forecasting variances being large in an absolute sense. With the forecast of capital costs being

$686.5 million (per the EB-2012-0451 Decision), and an anticipated in-service date of October 2015, even a modest forecast cost or timing 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 and B, which are projected to have construction commence in 2014 / 2015 with an in service date of October 2015. Attached as Appendix D to Updated Exhibit C1, Tab 5, Schedule 1, EGD has provided the forecast Allowed Revenue impact of the Segment A Parkway to Albion transportation pipeline of the overall project, as embedded within the EGD overall Allowed Revenues for 2015-2018. EGD proposes to treat the Segment A Parkway to Albion transportation portion as a separate cost center based on which Rate 332 will be developed. Rate 332 would recover the Allowed Revenue associated with 60% of the Segment A Parkway to Albion transportation pipeline and would exist over the agreed contractual terms with sufficient termination provisions to ensure any unrecovered capital amounts are not unduly cross-subsidized by EGD ratepayers.

6. The Allowed Revenue for the Segment A Parkway to Albion transportation pipeline portion as shown in Appendix D of Updated Exhibit C1, Tab 5, Schedule 1, includes the associated cost of capital, O&M, depreciation, and related taxes forecast to occur in each of fiscal years 2015 to 2018.

Witnesses: K. Culbert
C. Fernandes

CAPITAL STRUCTURE
TOTAL GTA PROJECT (2015 - 2018 Cap. Structure)

Line No.	(Excluding CIS)	Fiscal 2015 Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	Fiscal 2016 Col. 4 Component	Col. 5 Indicated Cost Rate	Col. 6 Return Component	Fiscal 2017 Col. 7 Component	Col. 8 Indicated Cost Rate	Col. 9 Return Component	Fiscal 2018 Col. 10 Component	Col. 11 Indicated Cost Rate	Col. 12 Return Component
		%	%	%	%	%	%	%	%	%	%	%	%
1.	Long-term debt	61.63	5.39	3.32	60.63	5.33	3.23	60.86	5.31	3.23	60.70	5.36	3.25
2.	Short-term debt	0.26	2.75	0.01	1.57	3.35	0.05	1.41	4.30	0.06	1.62	4.30	0.07
3.		61.89		3.33	62.20		3.29	62.27		3.29	62.32		3.32
4.	Preference shares	2.11	3.68	0.08	1.80	4.32	0.08	1.73	4.64	0.08	1.68	4.64	0.08
5.	Common equity	36.00	9.72	3.50	36.00	10.12	3.64	36.00	10.17	3.66	36.00	10.27	3.70
6.	Required Return on Rate Base	100.00		6.91	100.00		7.01	100.00		7.03	100.00		7.10

Line No.	($000's)	2015	2016	2017	2018
7.	Ontario Utility Income	3,834.6	(3,443.6)	(4,307.0)	(5,086.4)
8.	Rate base	142,787.7	675,183.9	658,188.3	641,192.7
9.	Indicated rate of return	2.69 %	(0.51)%	(0.65)%	(0.79)%
10.	(Def.) / suff. in rate of return	(4.22)%	(7.52)%	(7.68)%	(7.89)%
11.	Net (def.) / suff.	(6,025.6)	(50,773.8)	(50,548.9)	(50,590.1)
12.	Gross (def.) / suff.	(8,198.1)	(69,080.0)	(68,774.0)	(68,830.1)

RATE BASE
TOTAL GTA PROJECT (2015 - 2018 Cap. Structure)

($000's)

Line No.		2015	2016	2017	2018
	Property, plant, and equipment				
1.	Cost or redetermined value	143,023.8	686,514.3	686,514.3	686,514.3
2.	Accumulated depreciation	(236.1)	(11,330.4)	(28,326.0)	(45,321.6)
3.		142,787.7	675,183.9	658,188.3	641,192.7
	Allowance for working capital				
4.	Accounts receivable merchandise finance plan	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-
6.	Materials and supplies	-	-	-	-
7.	Mortgages receivable	-	-	-	-
8.	Customer security deposits	-	-	-	-
9.	Prepaid expenses	-	-	-	-
10.	Gas in storage	-	-	-	-
11.	Working cash allowance	-	-	-	-
12.		-	-	-	-
13.	Ontario utility rate base	142,787.7	675,183.9	658,188.3	641,192.7

INCOME
TOTAL GTA PROJECT (2015 - 2018 Cap. Structure)

($000's)

Line No.		2015	2016	2017	2018
	Revenue				
1.	Gas sales	-	-	-	-
2.	Transportation of gas	-	-	-	-
3.	Transmission and compression	-	-	-	-
4.	Other operating revenue	-	-	-	-
5.	Other income	-	-	-	-
6.	Total revenue	-	-	-	-
	Costs and expenses				
7.	Gas costs	-	-	-	-
8.	Operation and Maintenance	285.6	1,398.4	1,442.0	1,487.0
9.	Depreciation and amortization	2,832.6	16,995.6	16,995.6	16,995.6
10.	Municipal and other taxes	370.4	1,795.5	1,889.9	1,989.4
11.	Total costs and expenses	3,488.6	20,189.5	20,327.6	20,472.0
12.	**Utility income before inc. taxes**	(3,488.6)	(20,189.5)	(20,327.6)	(20,472.0)
	Income taxes				
13.	Excluding interest shield	(6,063.2)	(10,859.3)	(10,282.2)	(9,744.4)
14.	Tax shield on interest expense	(1,260.0)	(5,886.6)	(5,738.4)	(5,641.2)
15.	Total income taxes	(7,323.2)	(16,745.9)	(16,020.6)	(15,385.6)
16.	**Ontario utility net income**	3,834.6	(3,443.6)	(4,307.0)	(5,086.4)

TAXABLE INCOME AND INCOME TAX EXPENSE
TOTAL GTA PROJECT (2015 - 2018 Cap. Structure)

($000's)

Line No.		2015	2016	2017	2018
1.	Utility income before income taxes	(3,488.6)	(20,189.5)	(20,327.6)	(20,472.0)
	Add Backs				
2.	Depreciation and amortization	2,832.6	16,995.6	16,995.6	16,995.6
3.	Large corporation tax	-	-	-	-
4.	Other non-deductible items	-	-	-	-
5.	Any other add back(s)	-	-	-	-
6.	Total added back	2,832.6	16,995.6	16,995.6	16,995.6
7.	Sub total - pre-tax income plus add backs	(656.0)	(3,193.9)	(3,332.0)	(3,476.4)
	Deductions				
8.	Capital cost allowance - Federal	16,947.0	32,877.2	30,904.5	29,050.3
9.	Capital cost allowance - Provincial	16,947.0	32,877.2	30,904.5	29,050.3
10.	Items capitalized for regulatory purposes	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-
13.	Amortization of cumulative eligible capital	5,276.9	4,907.5	4,564.0	4,244.5
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-
15.	Any other deduction(s)	-	-	-	-
16.	Total Deductions - Federal	22,223.9	37,784.7	35,468.5	33,294.8
17.	Total Deductions - Provincial	22,223.9	37,784.7	35,468.5	33,294.8
18.	Taxable income - Federal	(22,879.9)	(40,978.6)	(38,800.5)	(36,771.2)
19.	Taxable income - Provincial	(22,879.9)	(40,978.6)	(38,800.5)	(36,771.2)
20.	Income tax provision - Federal	(3,432.0)	(6,146.8)	(5,820.1)	(5,515.7)
21.	Income tax provision - Provincial	(2,631.2)	(4,712.5)	(4,462.1)	(4,228.7)
22.	Income tax provision - combined	(6,063.2)	(10,859.3)	(10,282.2)	(9,744.4)
23.	Part V1.1 tax	-	-	-	-
24.	Investment tax credit	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(6,063.2)	(10,859.3)	(10,282.2)	(9,744.4)
	Tax shield on interest expense				
26.	Rate base as adjusted	142,787.7	675,183.9	658,188.3	641,192.7
27.	Return component of debt	3.33%	3.29%	3.29%	3.32%
28.	Interest expense	4,754.8	22,213.6	21,654.4	21,287.6
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(1,260.0)	(5,886.6)	(5,738.4)	(5,641.2)
31.	**Total income taxes**	(7,323.2)	(16,745.9)	(16,020.6)	(15,385.6)

ALLOWED REVENUE
TOTAL GTA PROJECT (2015 - 2018 Cap. Structure)

Line No.	($000's)	2015	2016	2017	2018
	Cost of capital				
1.	Rate base	142,787.7	675,183.9	658,188.3	641,192.7
2.	Required rate of return	6.91%	7.01%	7.03%	7.10%
3.	Cost of capital	9,866.6	47,330.4	46,270.6	45,524.7
	Cost of service				
4.	Gas costs	-	-	-	-
5.	Operation and Maintenance	285.6	1,398.4	1,442.0	1,487.0
6.	Depreciation and amortization	2,832.6	16,995.6	16,995.6	16,995.6
7.	Municipal and other taxes	370.4	1,795.5	1,889.9	1,989.4
8.	Cost of service	3,488.6	20,189.5	20,327.6	20,472.0
	Misc. & Non-Op. Rev				
9.	Other operating revenue	-	-	-	-
10.	Other income	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-
	Income taxes on earnings				
12.	Excluding tax shield	(6,063.2)	(10,859.3)	(10,282.2)	(9,744.4)
13.	Tax shield provided by interest expense	(1,260.0)	(5,886.6)	(5,738.4)	(5,641.2)
14.	Income taxes on earnings	(7,323.2)	(16,745.9)	(16,020.6)	(15,385.6)
	Taxes on (def) / suff.				
15.	Gross (def.) / suff.	(8,198.1)	(69,080.0)	(68,774.0)	(68,830.1)
16.	Net (def.) / suff.	(6,025.6)	(50,773.8)	(50,548.9)	(50,590.1)
17.	Taxes on (def.) / suff.	2,172.5	18,306.2	18,225.1	18,240.0
18.	**Allowed Revenue**	8,204.5	69,080.2	68,802.7	68,851.1
	Revenue at existing Rates				
19.	Gas sales	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0
22.	Rounding adjustment	6.4	(17.7)	11.3	21.0
23.	Revenue at existing rates	6.4	(17.7)	11.3	21.0
24.	**Gross revenue (def.) / suff.**	(8,198.1)	(69,097.9)	(68,791.4)	(68,830.1)

2015-2018 GREATER TORONTO AREA INCREMENTAL TRANSMISSION CAPITAL REVENUE REQUIREMENT DEFERRAL ACCOUNT ("GTAITCRRDA")

1. In the Decision in the Greater Toronto Area ("GTA") Leave-to-Construct (LTC) proceeding, EB-2012-0451, the Board ordered the Company to create a deferral account to track the revenue requirement impact in relation to $55 million in incremental capital spending which resulted from the upsizing of the transmission component of Segment A within the GTA project. In accordance with the Decision, the Company filed a Draft Accounting Order seeking approval to establish the Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA"). The Accounting Order was subsequently approved on March 11, 2014.

2. The purpose of the GTAITCRRDA will be to record the revenue requirement related to an incremental $55 million of forecast capital costs which resulted from the upsizing Segment A of the GTA project to an NPS 42 pipeline, from an NPS 36 pipeline. The account will only be required in the event that at the time Segment A is put into service there are no transportation customer(s), or there is no ability for transportation customer(s) to utilize Segment A (i.e., TransCanada's King's North project is delayed).

3. The revenue requirement will represent revenue to be collected from transportation service customers once they are able to take service under Rate 332: Parkway to Albion Transportation Service. The rationale for calculating the revenue requirement associated with the incremental $55 million is to determine the annual impact of the incremental costs to be paid by transportation customers as a result of upsizing the pipeline for transportation purposes.

Witness: K. Culbert

4. The revenue requirement amount, in relation to the incremental $55 million in capital costs, would be calculated utilizing the following steps.

   a) Determine the revenue requirement (cost of capital, operating costs, depreciation, income taxes) for the entire Segment A capital costs.
   b) The incremental $55 million of capital costs represent 14.3% of the forecast total Segment A capital cost amounts, as approved by the Board within EGD's accounting order request required by the Board in it's GTA LTC Decision.
   c) The revenue requirement associated with the incremental $55 million will be calculated by multiplying the total Segment A revenue requirement by the percentage of the incremental capital cost to total capital cost as shown above (14.3%).

5. 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

IMPACT STATEMENT NUMBER 1

1. This exhibit has been prepared and filed in order to reflect the impact of certain changes which are required within Enbridge Gas Distribution's 2014 through 2018 Customized Incentive Regulation rate application.

   The required changes are in relation to the following:

   a) An update of the GTA information and related costs to match the last updated costs resident within the Board Approved GTA LTC proceeding.
   b) The impact of updating for corrected lag day information as identified in Exhibit I.B18.EGDI.EP22 and within TCU3.21.

2. The impacts of the above noted adjustments and to the allowed revenues calculated for each of the fiscal years 2014 through 2018 are shown within the attached Schedules 2 through 6. Within each of the schedules for each fiscal year, the adjustments are specifically visible in Column 2 of pages 1, 2, 5 & 7, and in Column 4 in Schedule 8 which shows a new total allowed revenue and deficiency excluding and including Customer Care / CIS. The adjustments are in relation to only the utility income, rate base, and revenue requirement amounts exclusive of and do not affect the Customer Care / CIS settlement agreement amounts and impacts.

   Required changes

3. Within the GTA project written evidence in this proceeding, (Updated 2014-03-04, Exhibit C1, Tab 5, Schedule 1), EGD indicated that it would update the GTA forecast costs resident within its allowed revenue amounts for each year to match those last filed within the GTA LTC proceeding. The last update of costs within the Boards review and approval of the GTA LTC was related to changes in the scope and size of the Segment A pipeline within the total project from a 36 inch to a 42 inch pipeline. The details of that change, which were extensively reviewed and approved by the Board in the EB-2012-0451 GTA LTC proceeding, resulted in an increase in the project capital costs of $105.6 million to $686.5 million versus the level of $580.9 million projected and resident within the allowed revenue amounts contained

within the original evidence within this EB-2012-0459, 2014-2018 proceeding. The impact of the GTA forecast cost increase within each of the 2015 through 2018 allowed revenue results are approximate increases of $1.2 million to the 2015 deficiency, $10.2 million to the 2016 deficiency, $10.1 million to the 2017 deficiency and $10.1 million to the 2018 deficiency.

4. Additionally, as indicated in the evidence in Exhibits I.B18.EGDI.EP.22 and TCU3.21, the working cash allowance amounts included within rate base for each of 2014 through 2018 included an error within the revenue lag day calculation and resulting net lag day amounts being applied within the working cash calculations. EGD has corrected the net lag day and affected HST amounts using the proper net lag days within the derivation of working cash allowance, seen on page 4 of 8, within each of the Exhibit M1, Schedules 2 through 6. The impact of the net lag day corrections within each of the 2014 through 2018 allowed revenue and sufficiency/ (deficiency) results is as follows. An increase to the 2014 sufficiency of $2 million, a decrease to the 2015 deficiency of $2.9 million, a decrease to the 2016 deficiency of $4.2 million, a decrease to the 2017 deficiency of $3.7 million and a decrease to the 2018 deficiency of $4.0 million.

5. The result of the above noted adjustments within each of the Utility, Allowed Revenue, Rate Base, Income and Capital Structure determinations are shown within each of the attached Schedules 2 through 6. These adjustments do not affect the impacts of the Customer Care / CIS approved settlement included within the overall allowed revenue and deficiencies for each year. The resulting total impact on the gross revenue sufficiency/ (deficiency) for each of fiscal years 2014 through 2018 is as follows. The 2014 $31.2 million sufficiency becomes a $33.2 million sufficiency. The 2015 $(29.1) million deficiency becomes a $(27.4) million deficiency. The 2016 $(119.7) million deficiency becomes a $(125.7) million deficiency. The 2017 $(166.1) million deficiency becomes a $(172.5) million deficiency and the 2018 $(215.7) million deficiency becomes a $(221.8) million deficiency.

CHANGE IN ALLOWED REVENUE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-11-22 F3.T1.S1.P2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Impact Statement Number 1 EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,373.8	(34.1)	4,339.7	57.8	4,397.5
2.	Required rate of return	6.75	0.02	6.77	6.44	6.77
3.		295.2	(1.4)	293.8	3.7	297.5
	Cost of service					
4.	Gas costs	1,455.9	-	1,455.9	-	1,455.9
5.	Operation and maintenance	332.7	-	332.7	92.6	425.3
6.	Depreciation and amortization	250.1	-	250.1	12.7	262.8
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	41.2	-	41.2	-	41.2
9.		2,081.8	-	2,081.8	105.3	2,187.1
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(40.5)	-	(40.5)	-	(40.5)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(40.6)	-	(40.6)	-	(40.6)
	Income taxes on earnings					
14.	Excluding tax shield	64.3	-	64.3	8.7	73.0
15.	Tax shield provided by interest expense	(38.8)	0.1	(38.7)	(0.7)	(39.4)
16.		25.5	0.1	25.6	8.0	33.6
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	35.1	2.0	37.1	-	37.1
18.	Net sufficiency / (deficiency)	25.8	1.5	27.3	-	27.3
19.		(9.3)	(0.5)	(9.8)	-	(9.8)
20.	**Sub-total revenue requirement**	2,352.6	(1.8)	2,350.8	117.0	2,467.8
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(2.9)	(2.9)
22.	**Allowed revenue**	2,352.6	(1.8)	2,350.8	114.1	2,464.9
	Revenue at existing Rates					
23.	Gas sales	2,161.7	-	2,161.7	91.8	2,253.5
24.	Transportation service	224.4	-	224.4	18.4	242.8
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	(0.2)	0.2	-	-	-
27.	Revenue at existing rates	2,387.7	0.2	2,387.9	110.2	2,498.1
28.	**Gross revenue sufficiency / (deficiency)**	35.1	2.0	37.1	(3.9)	33.2

Note 1: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2013-11-22.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, Page 2, Filed: 2013-11-22.

UTILITY RATE BASE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-11-22 F3.T1.S3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,977.0	-	6,977.0	127.1	7,104.1
2.	Accumulated depreciation	(2,895.7)	-	(2,895.7)	(69.3)	(2,965.0)
3.		4,081.3	-	4,081.3	57.8	4,139.1
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
5.	Materials and supplies	32.8	-	32.8	-	32.8
6.	Mortgages receivable	0.1	-	0.1	-	0.1
7.	Customer security deposits	(65.7)	-	(65.7)	-	(65.7)
8.	Prepaid expenses	0.9	-	0.9	-	0.9
9.	Gas in storage	279.9	-	279.9	-	279.9
10.	Working cash allowance	43.2	(34.1)	9.1	-	9.1
11.	Total Working Capital	292.5	(34.1)	258.4	-	258.4
12.	Utility Rate Base	4,373.8	(34.1)	4,339.7	57.8	4,397.5

Note 1: Information from Col. 1 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2013-11-22.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2013-11-22.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2014 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	(34.1)	Working cash allowance Change due to the impact of a correction in the derivation of the revenue lag day downwards by 6 days, and its impact on the calculation of gas purchases, O&M and HST working cash requirements on page 4.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2014 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,469.5	2.8	11.3
2.	Items not subject to working cash allowance (Note 1)		(13.6)		
3.	Gas costs charged to operations	M1.T1.S2.P5.Col.3.L8	1,455.9		
4.	Operation and Maintenance	M1.T1.S2.P5.Col.3.L9	332.7		
5.	Less: Storage costs		(7.2)		
6.	Operation and maintenance costs subject to working cash		325.5		
7.	Ancillary customer services		-		
8.			325.5	(11.0)	(9.8)
9.	Sub-total				1.5
10.	Storage costs		7.2	65.9	1.3
11.	Storage municipal and capital taxes		1.3	23.3	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				6.2
14.	Total working cash allowance				9.1

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-11-22 F3.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,161.7	-	2,161.7	91.8	2,253.5
2.	Transportation of gas	224.4	-	224.4	18.4	242.8
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	40.5	-	40.5	-	40.5
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,428.5	-	2,428.5	110.2	2,538.7
8.	Gas costs	1,455.9	-	1,455.9	-	1,455.9
9.	Operation and maintenance	332.7	-	332.7	92.6	425.3
10.	Depreciation and amortization expense	250.1	-	250.1	12.7	262.8
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	41.2	-	41.2	-	41.2
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,081.8	-	2,081.8	105.3	2,187.1
16.	Ontario utility income before income taxes	346.7	-	346.7	4.9	351.6
17.	Income tax expense	25.5	0.1	25.6	8.0	33.6
18.	Utility net income	321.2	(0.1)	321.1	(3.1)	318.0

Note 1: Information from Col. 1 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2013-11-22.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2013-11-22.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2014 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
17.	0.1	Income tax expense Change in income tax expense related to a reduction in interest tax shield resulting from the decrease in rate base in relation to the working cash allowance correction.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-11-22 D3.T1.S1.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S2, P5)	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 - Federal	231.4	-	231.4
8.	Capital cost allowance - Provincial	231.4	-	231.4
9.	Items capitalized for regulatory purposes	45.9	-	45.9
10.	Deduction for "grossed up" Part VI.1 tax	3.5	-	3.5
11.	Amortization of share/debenture issue expense	3.9	-	3.9
12.	Amortization of cumulative eligible capital	0.3	-	0.3
13.	Amortization of C.D.E. and C.O.G.P.E	0.2	-	0.2
14.	Site restoration cost adjustment	68.1	-	68.1
15.	Cash based pension and OPEB costs	44.3	-	44.3
16.	Total Deduction - Federal	397.6	-	397.6
17.	Total Deduction - Provincial	397.6	-	397.6
18.	Taxable income - Federal	237.9	-	237.9
19.	Taxable income - Provincial	237.9	-	237.9
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	35.7	-	35.7
23.	Income tax provision - Provincial	27.4	-	27.4
24.	Income tax provision - combined	63.1	-	63.1
25.	Part V1.1 tax			1.2
26.	Total taxes excluding tax shield on interest expense			64.3
	Tax shield on interest expense			
27.	Rate base (M1.T1.S2.P2)			4,339.7
28.	Return component of debt (M1.T1.S2.P8)			3.37%
29.	Interest expense			146.1
30.	Combined tax rate			26.50%
31.	Income tax credit			(38.7)
32.	Total income taxes			25.6

Note 1: Information from Col. 1 and Col. 2 of Exhibit D3, Tab 1, Schedule 1, page 3, Filed: 2013-11-22.

UTILITY CAPITAL STRUCTURE
2014 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,596.9	59.84	5.57	3.333
2.	Short term debt	80.5	1.85	1.78	0.033
3.		2,677.4	61.69		3.366
4.	Preference shares	100.0	2.30	2.96	0.068
5.	Common equity	1,562.3	36.00	9.27	3.337
6.		4,339.7	99.99		6.771
7.	Utility income	($Millions)			321.1
8.	Rate base	($Millions)			4,339.7
9.	Indicated rate of return				7.399%
10.	Sufficiency in rate of return				0.628 %
11.	Net sufficiency	($Millions)			27.3
12.	Gross sufficiency	($Millions)			37.1
13.	Customer Care/CIS deficiency	($Millions)			(3.9)
14.	Total gross sufficiency	($Millions)			33.2
15.	Revenue at existing rates	($Millions)			2,498.1
16.	Allowed revenue	($Millions)			2,464.9
17.	Total gross revenue sufficiency	($Millions)			33.2

CHANGE IN ALLOWED REVENUE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F4.T1.S1.P2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Impact Statement Number 1 EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,752.5	(17.2)	4,735.3	45.1	4,780.4
2.	Required rate of return	6.90	0.01	6.91	6.44	6.91
3.		327.9	(0.7)	327.2	2.9	330.1
	Cost of service					
4.	Gas costs	1,606.8	-	1,606.8	-	1,606.8
5.	Operation and maintenance	332.0	-	332.0	96.5	428.5
6.	Depreciation and amortization	263.9	0.4	264.3	12.7	277.0
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	43.1	-	43.1	-	43.1
9.		2,247.7	0.4	2,248.1	109.2	2,357.3
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(40.9)	-	(40.9)	-	(40.9)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.0)	-	(41.0)	-	(41.0)
	Income taxes on earnings					
14.	Excluding tax shield	48.0	(0.9)	47.1	8.3	55.4
15.	Tax shield provided by interest expense	(41.9)	0.1	(41.8)	(0.6)	(42.4)
16.		6.1	(0.8)	5.3	7.7	13.0
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(20.6)	1.7	(18.9)	-	(18.9)
18.	Net sufficiency / (deficiency)	(15.2)	1.2	(13.9)	-	(13.9)
19.		5.5	(0.5)	5.0	-	5.0
20.	**Sub-total revenue requirement**	2,546.2	(1.6)	2,544.6	119.8	2,664.4
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(1.1)	(1.1)
22.	**Allowed revenue**	2,546.2	(1.6)	2,544.6	118.7	2,663.3
	Revenue at existing Rates					
23.	Gas sales	2,312.5	-	2,312.5	91.8	2,404.3
24.	Transportation service	211.2	-	211.2	18.4	229.6
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	0.1	0.1	0.2	-	0.2
27.	Revenue at existing rates	2,525.6	0.1	2,525.7	110.2	2,635.9
28.	**Gross revenue sufficiency / (deficiency)**	(20.6)	1.7	(18.9)	(8.5)	(27.4)

Note 1: Information from Col. 2 of Exhibit F4, Tab 1, Schedule 1, Page 2, Filed: 2013-06-28.
Note 2: Information from Col. 3 of Exhibit F4, Tab 1, Schedule 1, Page 2, Filed: 2013-06-28.

UTILITY RATE BASE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F4.T1.S3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	7,441.0	21.9	7,462.9	127.1	7,590.0
2.	Accumulated depreciation	(3,000.6)	(0.1)	(3,000.7)	(82.0)	(3,082.7)
3.		4,440.4	21.8	4,462.2	45.1	4,507.3
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
5.	Materials and supplies	33.7	-	33.7	-	33.7
6.	Mortgages receivable	0.1	-	0.1	-	0.1
7.	Customer security deposits	(65.1)	-	(65.1)	-	(65.1)
8.	Prepaid expenses	0.9	-	0.9	-	0.9
9.	Gas in storage	291.2	-	291.2	-	291.2
10.	Working cash allowance	50.0	(39.0)	11.0	-	11.0
11.	Total Working Capital	312.1	(39.0)	273.1	-	273.1
12.	Utility Rate Base	4,752.5	(17.2)	4,735.3	45.1	4,780.4

Note 1: Information from Col. 1 of Exhibit F4, Tab 1, Schedule 3, page 1, Filed: 2013-06-28.
Note 2: Information from Col. 2 of Exhibit F4, Tab 1, Schedule 3, page 1, Filed: 2013-06-28.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2015 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	21.9	Cost or redetermined value Change is due to the increase of $105.6 in capital costs as reviewed and approved within the GTA LTC proceeding. The increase in costs closes into service in October 2015 which results in a 2015 average of monthly averages increase as shown.
2.	(0.1)	Accumulated depreciation Change is due to the increase in depreciation expense and related increase in accumulated depreciation associated with the increase in the GTA costs noted above.
10.	(39.0)	Working cash allowance Change due to the impact of a correction in the derivation of the revenue lag day downwards by 6.2 days, and its impact on the calculation of gas purchases, O&M and HST working cash requirements on page 4.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2015 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,621.1	2.7	12.0
2.	Items not subject to working cash allowance (Note 1)		(14.3)		
3.	Gas costs charged to operations	M1.T1.S3.P5.Col.3.L8	1,606.8		
4.	Operation and Maintenance	M1.T1.S3.P5.Col.3.L9	332.0		
5.	Less: Storage costs		(8.0)		
6.	Operation and maintenance costs subject to working cash		324.0		
7.	Ancillary customer services		-		
8.			324.0	(11.1)	(9.9)
9.	Sub-total				2.1
10.	Storage costs		8.0	60.4	1.3
11.	Storage municipal and capital taxes		1.3	23.1	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				7.5
14.	Total working cash allowance				11.0

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F4.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,312.5	-	2,312.5	91.8	2,404.3
2.	Transportation of gas	211.2	-	211.2	18.4	229.6
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	40.9	-	40.9	-	40.9
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,566.5	-	2,566.5	110.2	2,676.7
8.	Gas costs	1,606.8	-	1,606.8	-	1,606.8
9.	Operation and maintenance	332.0	-	332.0	96.5	428.5
10.	Depreciation and amortization expense	263.9	0.4	264.3	12.7	277.0
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	43.1	-	43.1	-	43.1
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,247.7	0.4	2,248.1	109.2	2,357.3
16.	Ontario utility income before income taxes	318.8	(0.4)	318.4	1.0	319.4
17.	Income tax expense	6.1	(0.8)	5.3	7.7	13.0
18.	Utility net income	312.7	0.4	313.1	(6.7)	306.4

Note 1: Information from Col. 1 of Exhibit F4, Tab 1, Schedule 2, page 1, Filed: 2013-06-28.
Note 2: Information from Col. 2 of Exhibit F4, Tab 1, Schedule 2, page 1, Filed: 2013-06-28.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2015 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	0.4	Depreciation and amortization expense Change is due to the increase in depreciation expense associated with the increase in the GTA costs noted in the explanation of adjustments to Utility Rate Base on page 3.
17.	(0.8)	Income tax expense Change in income tax expense in relation to changes in taxable income resulting from the depreciation expense change noted above, changes in tax adds and deducts and interest tax shield resulting from the changes to rate base as shown and explained in pages 2 and 3 in this exhibit.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 D4.T1.S1.P3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M1, T1, S3, P5)	318.8	(0.4)	318.4
	Add			
2.	Depreciation and amortization	263.9	0.4	264.3
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	0.4	299.2
6.	Sub total	617.6	-	617.6
	Deduct			
7.	Capital cost allowance - Federal	279.5	2.7	282.2
8.	Capital cost allowance - Provincial	279.5	2.7	282.2
9.	Items capitalized for regulatory purposes	46.8	-	46.8
10.	Deduction for "grossed up" Part VI.1 tax	4.2	-	4.2
11.	Amortization of share/debenture issue expense	3.3	-	3.3
12.	Amortization of cumulative eligible capital	5.0	0.6	5.6
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Site restoration cost adjustment	63.1	-	63.1
15.	Cash based pension and OPEB costs	39.6	-	39.6
16.	Total Deduction - Federal	441.9	3.3	445.2
17.	Total Deduction - Provincial	441.9	3.3	445.2
18.	Taxable income - Federal	175.7	(3.3)	172.4
19.	Taxable income - Provincial	175.7	(3.3)	172.4
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	26.4	(0.5)	25.9
23.	Income tax provision - Provincial	20.2	(0.4)	19.8
24.	Income tax provision - combined	46.6	(0.9)	45.7
25.	Part V1.1 tax			1.4
26.	Total taxes excluding tax shield on interest expense			47.1
	Tax shield on interest expense			
27.	Rate base (M1.T1.S3.P2)			4,735.3
28.	Return component of debt (M1.T1.S3.P8)			3.33%
29.	Interest expense			157.6
30.	Combined tax rate			26.50%
31.	Income tax credit			(41.8)
32.	Total income taxes			5.3

Note 1: Information from Col. 1 and Col. 2 of Exhibit D4, Tab 1, Schedule 1, page 3, Filed: 2013-06-28.

UTILITY CAPITAL STRUCTURE
2015 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,918.4	61.63	5.39	3.322
2.	Short term debt	12.2	0.26	2.75	0.007
3.		2,930.6	61.89		3.329
4.	Preference shares	100.0	2.11	3.68	0.078
5.	Common equity	1,704.7	36.00	9.72	3.499
6.		4,735.3	100.00		6.906
7.	Utility income	($Millions)			313.1
8.	Rate base	($Millions)			4,735.3
9.	Indicated rate of return				6.612%
10.	(Deficiency) in rate of return				(0.294)%
11.	Net (deficiency)	($Millions)			(13.9)
12.	Gross (deficiency)	($Millions)			(18.9)
13.	Customer Care/CIS deficiency	($Millions)			(8.5)
14.	Total gross (deficiency)	($Millions)			(27.4)
15.	Revenue at existing rates	($Millions)			2,635.9
16.	Allowed revenue	($Millions)			2,663.3
17.	Total gross revenue (deficiency)	($Millions)			(27.4)

CHANGE IN ALLOWED REVENUE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F5.T1.S1.P2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Impact Statement Number 1 EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	5,492.0	61.8	5,553.8	32.4	5,586.2
2.	Required rate of return	7.02	(0.01)	7.01	6.44	7.01
3.		385.5	3.8	389.3	2.1	391.4
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	339.1	-	339.1	100.4	439.5
6.	Depreciation and amortization	291.2	2.7	293.9	12.7	306.6
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	45.5	-	45.5	-	45.5
9.		2,310.2	2.7	2,312.9	113.1	2,426.0
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	-	(41.2)	-	(41.2)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	-	(41.3)	-	(41.3)
	Income taxes on earnings					
14.	Excluding tax shield	45.0	(1.6)	43.4	7.9	51.3
15.	Tax shield provided by interest expense	(48.0)	(0.3)	(48.3)	(0.4)	(48.7)
16.		(3.0)	(1.9)	(4.9)	7.5	2.6
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(106.4)	(6.0)	(112.4)	-	(112.4)
18.	Net sufficiency / (deficiency)	(78.2)	(4.4)	(82.6)	-	(82.6)
19.		28.2	1.6	29.8	-	29.8
20.	**Sub-total revenue requirement**	2,679.6	6.2	2,685.8	122.7	2,808.5
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	0.8	0.8
22.	**Allowed revenue**	2,679.6	6.2	2,685.8	123.5	2,809.3
	Revenue at existing Rates					
23.	Gas sales	2,372.7	-	2,372.7	91.8	2,464.5
24.	Transportation service	198.7	-	198.7	18.4	217.1
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	-	0.2	0.2	-	0.2
27.	Revenue at existing rates	2,573.2	0.2	2,573.4	110.2	2,683.6
28.	**Gross revenue sufficiency / (deficiency)**	(106.4)	(6.0)	(112.4)	(13.3)	(125.7)

Note 1: Information from Col. 2 of Exhibit F5, Tab 1, Schedule 1, Page 2, Filed: 2013-06-28.
Note 2: Information from Col. 3 of Exhibit F5, Tab 1, Schedule 1, Page 2, Filed: 2013-06-28.

UTILITY RATE BASE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F5.T1.S3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	8,321.9	105.6	8,427.5	127.1	8,554.6
2.	Accumulated depreciation	(3,118.7)	(1.9)	(3,120.6)	(94.7)	(3,215.3)
3.		5,203.2	103.7	5,306.9	32.4	5,339.3
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	40.1	(41.9)	(1.8)	-	(1.8)
11.	Total Working Capital	288.8	(41.9)	246.9	-	246.9
12.	Utility Rate Base	5,492.0	61.8	5,553.8	32.4	5,586.2

Note 1: Information from Col. 1 of Exhibit F5, Tab 1, Schedule 3, page 1, Filed: 2013-06-28.
Note 2: Information from Col. 2 of Exhibit F5, Tab 1, Schedule 3, page 1, Filed: 2013-06-28.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2016 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	105.6	Cost or redetermined value Change is due to the increase of $105.6 million in capital costs as reviewed and approved within the GTA LTC proceeding.
2.	(1.9)	Accumulated depreciation Change is due to the increase in depreciation expense and related increase in accumulated depreciation associated with the increase in the GTA costs noted above.
10.	(41.9)	Working cash allowance Change due to the impact of a correction in the derivation of the revenue lag day downwards by 6.5 days, and its impact on the calculation of gas purchases, O&M and HST working cash requirements on page 4.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	M1.T1.S4.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	M1.T1.S4.P5.Col.3.L9	339.1		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		330.7		
7.	Ancillary customer services		-		
8.			330.7	(10.9)	(9.9)
9.	Sub-total				0.5
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(1.8)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 F5.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,372.7	-	2,372.7	91.8	2,464.5
2.	Transportation of gas	198.7	-	198.7	18.4	217.1
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2	-	41.2
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,614.5	-	2,614.5	110.2	2,724.7
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	339.1	-	339.1	100.4	439.5
10.	Depreciation and amortization expense	291.2	2.7	293.9	12.7	306.6
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	45.5	-	45.5	-	45.5
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,310.2	2.7	2,312.9	113.1	2,426.0
16.	Ontario utility income before income taxes	304.3	(2.7)	301.6	(2.9)	298.7
17.	Income tax expense	(3.0)	(1.9)	(4.9)	7.5	2.6
18.	Utility net income	307.3	(0.8)	306.5	(10.4)	296.1

Note 1: Information from Col. 1 of Exhibit F5, Tab 1, Schedule 2, page 1, Filed: 2013-06-28.
Note 2: Information from Col. 2 of Exhibit F5, Tab 1, Schedule 2, page 1, Filed: 2013-06-28.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2016 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	2.7	Depreciation and amortization expense Change is due to the increase in depreciation expense associated with the increase in the GTA costs noted in the explanation of adjustments to Utility Rate Base on page 3.
17.	(1.9)	Income tax expense Change in income tax expense in relation to changes in taxable income resulting from the depreciation expense change noted above, changes in tax adds and decucts and interest tax shield resulting from the changes to rate base as shown and explained in pages 2 and 3 in this exhibit.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-06-28 D5.T1.S1.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S4, P5)	304.3	(2.7)	301.6
	Add			
2.	Depreciation and amortization	291.2	2.7	293.9
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	2.7	325.8
6.	Sub total	627.4	-	627.4
	Deduct			
7.	Capital cost allowance - Federal	310.1	5.3	315.4
8.	Capital cost allowance - Provincial	310.1	5.3	315.4
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.8	-	3.8
12.	Amortization of cumulative eligible capital	4.7	0.5	5.2
13.	Amortization of C.D.E. and C.O.G.P.E	0.2	-	0.2
14.	Site restoration cost adjustment	58.1	-	58.1
15.	Cash based pension and OPEB costs	35.7	-	35.7
16.	Total Deduction - Federal	464.2	5.8	470.0
17.	Total Deduction - Provincial	464.2	5.8	470.0
18.	Taxable income - Federal	163.2	(5.8)	157.4
19.	Taxable income - Provincial	163.2	(5.8)	157.4
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	24.5	(0.9)	23.6
23.	Income tax provision - Provincial	18.8	(0.7)	18.1
24.	Income tax provision - combined	43.3	(1.6)	41.7
25.	Part V1.1 tax			1.7
26.	Total taxes excluding tax shield on interest expense			43.4
	Tax shield on interest expense			
27.	Rate base (M1.T1.S4.P2)			5,553.8
28.	Return component of debt (M1.T1.S4.P8)			3.29%
29.	Interest expense			182.4
30.	Combined tax rate			26.50%
31.	Income tax credit			(48.3)
32.	Total income taxes			(4.9)

Note 1: Information from Col. 1 and Col. 2 of Exhibit D5, Tab 1, Schedule 1, page 3, Filed: 2013-06-28.

UTILITY CAPITAL STRUCTURE
2016 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	3,367.0	60.63	5.33	3.232
2.	Short term debt	87.4	1.57	3.35	0.053
3.		3,454.4	62.20		3.285
4.	Preference shares	100.0	1.80	4.32	0.078
5.	Common equity	1,999.4	36.00	10.12	3.643
6.		5,553.8	100.00		7.006
7.	Utility income	($Millions)			306.5
8.	Rate base	($Millions)			5,553.8
9.	Indicated rate of return				5.519%
10.	(Deficiency) in rate of return				(1.487)%
11.	Net (deficiency)	($Millions)			(82.6)
12.	Gross (deficiency)	($Millions)			(112.4)
13.	Customer Care/CIS deficiency	($Millions)			(13.3)
14.	Total gross (deficiency)	($Millions)			(125.7)
15.	Revenue at existing rates	($Millions)			2,683.6
16.	Allowed revenue	($Millions)			2,809.3
17.	Total gross revenue (deficiency)	($Millions)			(125.7)

CHANGE IN ALLOWED REVENUE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F6.T1.S1.P2 (Note 1) ($Millions)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1 ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Impact Statement Number 1 EGD Total ($Millions)
	Cost of capital					
1.	Rate base	5,716.9	59.0	5,775.9	19.7	5,795.6
2.	Required rate of return	7.04	(0.01)	7.03	6.44	7.03
3.		402.5	3.5	406.0	1.3	407.3
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	346.1	-	346.1	104.4	450.5
6.	Depreciation and amortization	300.7	2.8	303.5	12.7	316.2
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	47.9	-	47.9	-	47.9
9.		2,329.1	2.8	2,331.9	117.1	2,449.0
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	-	(41.2)	-	(41.2)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	-	(41.3)	-	(41.3)
	Income taxes on earnings					
14.	Excluding tax shield	51.3	(1.5)	49.8	7.5	57.3
15.	Tax shield provided by interest expense	(50.0)	(0.4)	(50.4)	(0.2)	(50.6)
16.		1.3	(1.9)	(0.6)	7.3	6.7
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(147.7)	(6.4)	(154.1)	-	(154.1)
18.	Net sufficiency / (deficiency)	(108.6)	(4.6)	(113.2)	-	(113.2)
19.		39.1	1.7	40.8	-	40.8
20.	**Sub-total revenue requirement**	2,730.7	6.1	2,736.8	125.7	2,862.5
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	2.9	2.9
22.	**Allowed revenue**	2,730.7	6.1	2,736.8	128.6	2,865.4
	Revenue at existing Rates					
23.	Gas sales	2,388.5	-	2,388.5	91.8	2,480.3
24.	Transportation service	192.7	-	192.7	18.4	211.1
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	-	(0.3)	(0.3)	-	(0.3)
27.	Revenue at existing rates	2,583.0	(0.3)	2,582.7	110.2	2,692.9
28.	**Gross revenue sufficiency / (deficiency)**	(147.7)	(6.4)	(154.1)	(18.4)	(172.5)

Note 1: Information from Col. 2 of Exhibit F6, Tab 1, Schedule 1, Page 2, Filed: 2013-12-11.
Note 2: Information from Col. 3 of Exhibit F6, Tab 1, Schedule 1, Page 2, Filed: 2013-12-11.

UTILITY RATE BASE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F6.T1.S3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	8,686.6	105.6	8,792.2	127.1	8,919.3
2.	Accumulated depreciation	(3,258.4)	(4.6)	(3,263.0)	(107.4)	(3,370.4)
3.		5,428.2	101.0	5,529.2	19.7	5,548.9
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	40.0	(42.0)	(2.0)	-	(2.0)
11.	Total Working Capital	288.7	(42.0)	246.7	-	246.7
12.	Utility Rate Base	5,716.9	59.0	5,775.9	19.7	5,795.6

Note 1: Information from Col. 1 of Exhibit F6, Tab 1, Schedule 3, page 1, Filed: 2013-12-11.
Note 2: Information from Col. 2 of Exhibit F6, Tab 1, Schedule 3, page 1, Filed: 2013-12-11.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2017 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	105.6	Cost or redetermined value Change is due to the increase of $105.6 million in capital costs as reviewed and approved within the GTA LTC proceeding.
2.	(4.6)	Accumulated depreciation Change is due to the increase in depreciation expense and related increase in accumulated depreciation associated with the increase in the GTA costs noted above.
10.	(42.0)	Working cash allowance Change due to the impact of a correction in the derivation of the revenue lag day downwards by 6.5 days, and its impact on the calculation of gas purchases, O&M and HST working cash requirements on page 4.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2017 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	M1.T1.S5.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	M1.T1.S5.P5.Col.3.L9	346.1		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		337.7		
7.	Ancillary customer services		-		
8.			337.7	(10.9)	(10.1)
9.	Sub-total				0.3
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(2.0)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F6.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,388.5	-	2,388.5	91.8	2,480.3
2.	Transportation of gas	192.7	-	192.7	18.4	211.1
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2	-	41.2
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,624.3	-	2,624.3	110.2	2,734.5
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	346.1	-	346.1	104.4	450.5
10.	Depreciation and amortization expense	300.7	2.8	303.5	12.7	316.2
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	47.9	-	47.9	-	47.9
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,329.1	2.8	2,331.9	117.1	2,449.0
16.	Ontario utility income before income taxes	295.2	(2.8)	292.4	(6.9)	285.5
17.	Income tax expense	1.3	(1.9)	(0.6)	7.3	6.7
18.	Utility net income	293.9	(0.9)	293.0	(14.2)	278.8

Note 1: Information from Col. 1 of Exhibit F6, Tab 1, Schedule 2, page 1, Filed: 2013-12-11.
Note 2: Information from Col. 2 of Exhibit F6, Tab 1, Schedule 2, page 1, Filed: 2013-12-11.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2017 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	2.8	Depreciation and amortization expense Change is due to the increase in depreciation expense associated with the increase in the GTA costs noted in the explanation of adjustments to Utility Rate Base on page 3.
17.	(1.9)	Income tax expense Change in income tax expense in relation to changes in taxable income resulting from the depreciation expense change noted above, changes in tax adds and decucts and interest tax shield resulting from the changes to rate base as shown and explained in pages 2 and 3 in this exhibit.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 D6.T1.S1.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S5, P5)	295.2	(2.8)	292.4
	Add			
2.	Depreciation and amortization	300.7	2.8	303.5
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	2.8	333.0
6.	Sub total	625.4	-	625.4
	Deduct			
7.	Capital cost allowance - Federal	293.2	5.0	298.2
8.	Capital cost allowance - Provincial	293.2	5.0	298.2
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	-	5.6
11.	Amortization of share/debenture issue expense	3.9	-	3.9
12.	Amortization of cumulative eligible capital	4.3	0.5	4.8
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	-	0.1
14.	Site restoration cost adjustment	53.1	-	53.1
15.	Cash based pension and OPEB costs	32.2	-	32.2
16.	Total Deduction - Federal	439.0	5.5	444.5
17.	Total Deduction - Provincial	439.0	5.5	444.5
18.	Taxable income - Federal	186.4	(5.5)	180.9
19.	Taxable income - Provincial	186.4	(5.5)	180.9
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	28.0	(0.9)	27.1
23.	Income tax provision - Provincial	21.4	(0.6)	20.8
24.	Income tax provision - combined	49.4	(1.5)	47.9
25.	Part V1.1 tax			1.9
26.	Total taxes excluding tax shield on interest expense			49.8
	Tax shield on interest expense			
27.	Rate base (M1.T1.S5.P2)			5,775.9
28.	Return component of debt (M1.T1.S5.P8)			3.29%
29.	Interest expense			190.1
30.	Combined tax rate			26.50%
31.	Income tax credit			(50.4)
32.	Total income taxes			(0.6)

Note 1: Information from Col. 1 and Col. 2 of Exhibit D6, Tab 1, Schedule 1, page 3, Filed: 2013-12-11.

UTILITY CAPITAL STRUCTURE
2017 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	3,515.5	60.86	5.31	3.232
2.	Short term debt	81.1	1.40	4.30	0.060
3.		3,596.6	62.26		3.292
4.	Preference shares	100.0	1.73	4.64	0.080
5.	Common equity	2,079.3	36.00	10.17	3.661
6.		5,775.9	99.99		7.033
7.	Utility income	($Millions)			293.0
8.	Rate base	($Millions)			5,775.9
9.	Indicated rate of return				5.073%
10.	(Deficiency) in rate of return				(1.960)%
11.	Net (deficiency)	($Millions)			(113.2)
12.	Gross (deficiency)	($Millions)			(154.1)
13.	Customer Care/CIS deficiency	($Millions)			(18.4)
14.	Total gross (deficiency)	($Millions)			(172.5)
15.	Revenue at existing rates	($Millions)			2,692.9
16.	Allowed revenue	($Millions)			2,865.4
17.	Total gross revenue (deficiency)	($Millions)			(172.5)

CHANGE IN ALLOWED REVENUE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F7.T1.S1.P2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Impact Statement Number 1 EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	5,899.1	56.2	5,955.3	7.0	5,962.3
2.	Required rate of return	7.11	(0.01)	7.10	6.44	7.10
3.		419.4	3.4	422.8	0.5	423.3
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	353.3	-	353.3	108.5	461.8
6.	Depreciation and amortization	309.4	2.7	312.1	12.7	324.8
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	50.4	-	50.4	-	50.4
9.		2,347.5	2.7	2,350.2	121.2	2,471.4
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	-	(41.2)	-	(41.2)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	-	(41.3)	-	(41.3)
	Income taxes on earnings					
14.	Excluding tax shield	60.7	(1.4)	59.3	7.2	66.5
15.	Tax shield provided by interest expense	(52.0)	(0.5)	(52.5)	(0.1)	(52.6)
16.		8.7	(1.9)	6.8	7.1	13.9
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(192.1)	(6.1)	(198.2)	-	(198.2)
18.	Net sufficiency / (deficiency)	(141.2)	(4.4)	(145.7)	-	(145.7)
19.		50.9	1.6	52.5	-	52.5
20.	**Sub-total revenue requirement**	2,785.2	5.8	2,791.0	128.8	2,919.8
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	5.0	5.0
22.	**Allowed revenue**	2,785.2	5.8	2,791.0	133.8	2,924.8
	Revenue at existing Rates					
23.	Gas sales	2,404.4	-	2,404.4	91.8	2,496.2
24.	Transportation service	186.6	-	186.6	18.4	205.0
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	0.3	(0.3)	-	-	-
27.	Revenue at existing rates	2,593.1	(0.3)	2,592.8	110.2	2,703.0
28.	**Gross revenue sufficiency / (deficiency)**	(192.1)	(6.1)	(198.2)	(23.6)	(221.8)

Note 1: Information from Col. 2 of Exhibit F7, Tab 1, Schedule 1, Page 2, Filed: 2013-12-11.
Note 2: Information from Col. 3 of Exhibit F7, Tab 1, Schedule 1, Page 2, Filed: 2013-12-11.

UTILITY RATE BASE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F7.T1.S3 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Adjusted Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	9,042.2	105.6	9,147.8	127.1	9,274.9
2.	Accumulated depreciation	(3,431.7)	(7.3)	(3,439.0)	(120.1)	(3,559.1)
3.		5,610.5	98.3	5,708.8	7.0	5,715.8
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	39.9	(42.1)	(2.2)	-	(2.2)
11.	Total Working Capital	288.6	(42.1)	246.5	-	246.5
12.	Utility Rate Base	5,899.1	56.2	5,955.3	7.0	5,962.3

Note 1: Information from Col. 1 of Exhibit F7, Tab 1, Schedule 3, page 1, Filed: 2013-12-11.
Note 2: Information from Col. 2 of Exhibit F7, Tab 1, Schedule 3, page 1, Filed: 2013-12-11.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2018 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	105.6	Cost or redetermined value Change is due to the increase of $105.6 million in capital costs as reviewed and approved within the GTA LTC proceeding.
2.	(7.3)	Accumulated depreciation Change is due to the increase in depreciation expense and related increase in accumulated depreciation associated with the increase in the GTA costs noted above.
10.	(42.1)	Working cash allowance Change due to the impact of a correction in the derivation of the revenue lag day downwards by 6.5 days, and its impact on the calculation of gas purchases, O&M and HST working cash requirements on page 4.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2018 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements	Net Lag-Days	Allowance
			($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	M1.T1.S6.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	M1.T1.S6.P5.Col.3.L9	353.3		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		344.9		
7.	Ancillary customer services		-		
8.			344.9	(10.9)	(10.3)
9.	Sub-total				0.1
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(2.2)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 F7.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,404.4	-	2,404.4	91.8	2,496.2
2.	Transportation of gas	186.6	-	186.6	18.4	205.0
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	-	41.2	-	41.2
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,634.1	-	2,634.1	110.2	2,744.3
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	353.3	-	353.3	108.5	461.8
10.	Depreciation and amortization expense	309.4	2.7	312.1	12.7	324.8
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	50.4	-	50.4	-	50.4
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,347.5	2.7	2,350.2	121.2	2,471.4
16.	Ontario utility income before income taxes	286.6	(2.7)	283.9	(11.0)	272.9
17.	Income tax expense	8.7	(1.9)	6.8	7.1	13.9
18.	Utility net income	277.9	(0.8)	277.1	(18.1)	259.0

Note 1: Information from Col. 1 of Exhibit F7, Tab 1, Schedule 2, page 1, Filed: 2013-12-11.
Note 2: Information from Col. 2 of Exhibit F7, Tab 1, Schedule 2, page 1, Filed: 2013-12-11.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2018 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
10.	2.7	Depreciation and amortization expense Change is due to the increase in depreciation expense associated with the increase in the GTA costs noted in the explanation of adjustments to Utility Rate Base on page 3.
17.	(1.9)	Income tax expense Change in income tax expense in relation to changes in taxable income resulting from the depreciation expense change noted above, changes in tax adds and decucts and interest tax shield resulting from the changes to rate base as shown and explained in pages 2 and 3 in this exhibit.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS As Filed 2013-12-11 D7.T1.S1.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S6, P5)	286.6	(2.7)	283.9
	Add			
2.	Depreciation and amortization	309.4	2.7	312.1
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	2.7	339.3
6.	Sub total	623.2	-	623.2
	Deduct			
7.	Capital cost allowance - Federal	293.8	4.7	298.5
8.	Capital cost allowance - Provincial	293.8	4.7	298.5
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	-	5.6
11.	Amortization of share/debenture issue expense	4.0	-	4.0
12.	Amortization of cumulative eligible capital	4.0	0.5	4.5
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	-	0.1
14.	Site restoration cost adjustment	17.4	-	17.4
15.	Cash based pension and OPEB costs	29.8	-	29.8
16.	Total Deduction - Federal	401.3	5.2	406.5
17.	Total Deduction - Provincial	401.3	5.2	406.5
18.	Taxable income - Federal	221.9	(5.2)	216.7
19.	Taxable income - Provincial	221.9	(5.2)	216.7
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	33.3	(0.8)	32.5
23.	Income tax provision - Provincial	25.5	(0.6)	24.9
24.	Income tax provision - combined	58.8	(1.4)	57.4
25.	Part V1.1 tax			1.9
26.	Total taxes excluding tax shield on interest expense			59.3
	Tax shield on interest expense			
27.	Rate base (M1.T1.S6.P2)			5,955.3
28.	Return component of debt (M1.T1.S6.P8)			3.32%
29.	Interest expense			198.0
30.	Combined tax rate			26.50%
31.	Income tax credit			(52.5)
32.	Total income taxes			6.8

Note 1: Information from Col. 1 and Col. 2 of Exhibit D7, Tab 1, Schedule 1, page 3, Filed: 2013-12-11.

UTILITY CAPITAL STRUCTURE
2018 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	3,614.9	60.70	5.36	3.254
2.	Short term debt	96.5	1.62	4.30	0.070
3.		3,711.4	62.32		3.324
4.	Preference shares	100.0	1.68	4.64	0.078
5.	Common equity	2,143.9	36.00	10.27	3.697
6.		5,955.3	100.00		7.099
7.	Utility income	($Millions)			277.1
8.	Rate base	($Millions)			5,955.3
9.	Indicated rate of return				4.653%
10.	(Deficiency) in rate of return				(2.446)%
11.	Net (deficiency)	($Millions)			(145.7)
12.	Gross (deficiency)	($Millions)			(198.2)
13.	Customer Care/CIS deficiency	($Millions)			(23.6)
14.	Total gross (deficiency)	($Millions)			(221.8)
15.	Revenue at existing rates	($Millions)			2,703.0
16.	Allowed revenue	($Millions)			2,924.8
17.	Total gross revenue (deficiency)	($Millions)			(221.8)

UNDERTAKING J5.10

UNDERTAKING

TR 81

To provide 2013 actuals for Exhibit B2, Tab 5, Schedule 1, Table 1 and Table 2.

RESPONSE

Table 1 (Exhibit B2, Tab 5, Schedule 1)
(000's)

Item Number	Description	2013 Budget	2013 Actual	2014 Forecast	2015 Forecast	2016 Forecast
1	System Integrity and Reliability Totals	84,724	113,900	132,333	135,126	141,103
2	Variance Year over Year (000's)	N/A	N/A	18,433	2,793	5,977
3	Variance to Base Year (000's)	N/A	N/A	18,433	21,226	27,203
4	Percentage Variance to Base Year (%)	N/A	N/A	16%	19%	24%

Table 2 (Exhibit B2, Tab 5, Schedule 1)
(000's)

Item Number	Description	2013 Budget	2013 Actual	2014 Forecast	2015 Forecast	2016 Forecast
1	Mains Replacement	18,237	31,582	24,604	24,098	22,110
2	Service Replacement	17,814	23,551	21,118	25,011	41,216
3	Station Replacement	15,767	9,200	23,990	26,442	24,517
4	Other System Integrity and Reliability	32,906	35,058	41,808	42,650	35,810
5	System Integrity Direct Resource Costs	15,330	14,509	20,813	16,925	17,449
6	Total System Integrity and Reliability	84,724	113,900	132,333	135,126	141,103

Line 5, Column 2013 Budget - As explained within Exhibit B2, Tab 5, Schedule 6, the System Integrity Direct Resource Costs for 2013 are included directly within the Program costs for 2013. The total amount of 2013 System Integrity Direct Resource Costs included within the total $84.72 Million budget for 2013 is $15.33 Million. 2013 values have been included within item 6 for the 2013 columns (but not the totals), in order than those values may be used for comparison purposes within 2014 to 2016.
Line 6, Column 2013 Budget - Ibid.

Witness: L. Lawler

UNDERTAKING J9.4

UNDERTAKING

TR 113

To provide details regarding setting up a fund.

RESPONSE

Enbridge is unable to provide a reasonable estimate of what any initial set-up and annual operating costs might be in relation to any fund for employee related post-employment benefits, if it was required by the Ontario Energy Board to establish such a fund. Such costs would be specific to and determinative relative to, size, complexity, asset base, # of plans, type of investments, etc.

In communication with Enbridge Inc. ("EI"), it was indicated that the annual operating costs for post-employment benefits fund requirements for US based companies within EI's financials could be approximately $3 plus million. However, the list set out above of variables which would affect such costs, although not an exhaustive list, is an indication that the cost estimate from EI for its own costs is not likely an accurate representation of the level or types of costs which might be incurred within an entity like Enbridge in Ontario.

Witness: K. Culbert