RATE BASE EVIDENCE AND SUMMARIES

1. This evidence deals with information with respect to EGD's utility rate base and the levels of gross plant, accumulated depreciation and working capital elements within rate base.

2. The table found at Updated Exhibit B1, Tab 1, Schedule 2, is a summary showing the values on an average of average basis for each of these rate base components.

3. The 2014 fiscal year rate base of $4,431.6 million is higher by $269.6 million than the Board Approved 2013 rate base of $4,162.0 million. This increase is mainly due to property, plant and equipment costs and amounts closing into service offset partly by increases in accumulated depreciation along with an increase in the total required working capital. The increase in net property, plant and equipment of $193.8 million, is the result of the level of customer related capital amounts which close into service, an increased level of system improvement related capital requirements including the Ottawa reinforcement project closing into service in 2014 along with the impact of annual depreciation and increased accumulated depreciation which were partially reduced by the impact of the proposed reduction in certain distribution related asset depreciation rates. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $68.1 million to ratepayers in 2014 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $39.8 million due to the monthly pattern of the rate rider. The increase in working capital of $75.8 million is mainly the result of an anticipated increase in the value of gas in storage along with an increase in the required working cash allowance resulting from an increase in net working cash lag days and HST related working cash mostly from the increased level of capital spending.

Witness: K. Culbert

4. The 2015 forecast year rate base of $4,797.6 million is higher by $366.0 million than the 2014 fiscal year rate base of $4,431.6 million. The increase in net property, plant and equipment of $346.4 million, is the result of a slightly higher customer related capital amounts, an increased level of system improvement related capital requirements including the GTA project closing into service in October 2015, the partial year impact of the WAMS project closing into service in December 2015, along with the impact of annual depreciation and increased accumulated depreciation. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $63.1 million to ratepayers in 2015 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $36.8 million due to the monthly pattern of the rate rider. Working capital also increased by $19.6 million over 2014 mainly the result of an anticipated increase in the value of gas in storage along with an increase in the required working cash allowance mostly as a result of anticipated increases in gas cost and HST related working cash from the increased level of capital related spending.

5. The 2016 forecast year rate base of $5,524.4 million is higher by $726.8 million than the 2015 forecast year rate base of $4,797.6 million. The increase in net property, plant and equipment of $750.1 million, is the result of a slightly higher customer related capital amounts, the full year 2016 rate base impacts of the previous year's GTA and WAMS projects which closed into service late in 2015 along with the impact of annual depreciation and increased accumulated depreciation. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $58.1 million to ratepayers in 2016 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $33.9 million due to the

monthly pattern of the rate rider. Working capital decreased by $23.3 million compared to 2015 mainly the result of an anticipated decrease in the value of gas in storage along with a decrease in the required working cash allowance mostly as a result of an anticipated decrease in HST related working cash from the decreased level of capital related spending.

6. The 2017 forecast year rate base of $5,736.6 million is higher by $212.2 million than the 2016 forecast year rate base of $5,524.4 million. The increase in net property, plant and equipment of $212.3 million, has been derived by using the 2016 forecast year amounts of capital spend and amounts closing into service as being a reasonable estimate of amounts which would affect the forecast 2017 property, plant and equipment. As explained in evidence at Exhibit A2, Tab 1, Schedule 1, the 2016 forecast customer additions have been assumed to be a reasonable estimate to be used in 2017 and as a result the capital expenditure related impacts have been assumed to be mostly the same as 2016. However, amounts forecast to be closing into service in 2016 in relation to the WAMS project, $8 million, have been removed from the capital related amounts used to calculate the 2017 net property, plant and equipment and rate base. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $53.1 million to ratepayers in 2017 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $31.0 million due to the monthly pattern of the rate rider. Working capital elements have been assumed to remain at the same level in 2017 as forecast in 2016 other than a slight change to working cash resulting from the forecast change in O&M which is an element contained within the working cash calculation.

7. The 2018 forecast year rate base of $5,906.1 million is higher by $169.5 million than the 2017 forecast year rate base of $5,736.6 million. The increase in net property, plant and equipment of $169.6 million, has been derived by using the 2016 forecast year amounts of capital spend and amounts closing into service as being a reasonable estimate of amounts which would affect the forecast 2018 property, plant and equipment. The adjusted estimated amounts of 2017 capital expenditure related impacts have been assumed to be a reasonable estimate to be used in 2018 to calculate the 2018 net property, plant and equipment and rate base. Additionally, as explained in evidence at Exhibit D1, Tab 8, Schedule 3, the effect of the proposal to establish a rate rider to clear a net salvage value amount of $17.4 million to ratepayers in 2018 has an effect of decreasing accumulated depreciation and increasing rate base by approximately $10.1 million due to the monthly pattern of the rate rider. Working capital elements have been assumed to remain at the same level in 2018 as estimated in 2017 other than a slight change to working cash resulting from the forecast change in O&M which is an element contained within the working cash calculation.

8. Details and explanations of 2014 through 2018 budgeted capital expenditures can be found in Updated Exhibit B2, Tab 1, Schedule 1.

9. Continuity schedules for gross property, plant and equipment, accumulated depreciation and working capital related elements can be found in Exhibits B3, B4, B5, B6 and B7, Tab 1, Schedules 1, 2 & 3.

UTILITY RATE BASE (INCLUDING CIS & CUSTOMER CARE)
YEAR TO YEAR SUMMARY

Line No.		Col. 1 2013 Board Approved	Col. 2 2014 Fiscal Year	Col. 3 2015 Fiscal Year	Col. 4 2016 Fiscal Year	Col. 5 2017 Fiscal Year	Col. 6 2018 Fiscal Year
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment						
1.	Cost or redetermined value	6,749.4	7,104.1	7,568.1	8,449.0	8,813.7	9,169.3
2.	Accumulated depreciation	(2,804.1)	(2,965.0)	(3,082.6)	(3,213.4)	(3,365.8)	(3,551.8)
3.		3,945.3	4,139.1	4,485.5	5,235.6	5,447.9	5,617.5
	Allowance for Working Capital						
4.	Accounts receivable rebillable projects	1.3	1.3	1.3	1.4	1.4	1.4
5.	Materials and supplies	31.9	32.8	33.7	34.6	34.6	34.6
6.	Mortgages receivable	0.2	0.1	0.1	-	-	-
7.	Customer security deposits	(68.7)	(65.7)	(65.1)	(64.6)	(64.6)	(64.6)
8.	Prepaid expenses	1.8	0.9	0.9	1.0	1.0	1.0
9.	Gas in storage	248.4	279.9	291.2	276.3	276.3	276.3
10.	Working cash allowance	1.8	43.2	50.0	40.1	40.0	39.9
11.	Total Working Capital	216.7	292.5	312.1	288.8	288.7	288.6
12.	Utility Rate Base	4,162.0	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1

ECONOMIC FEASIBILITY PROCEDURE AND POLICY

Introduction

1. The purpose of this evidence is to present the current procedures and policies for determining the feasibility of the Company's system expansion projects. These procedures and policies are adopted to comply with the Ontario Energy Board's (the "Board") "*Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*", reported under EBO 188 dated January 30, 1998.

2. This evidence includes an overview of the Company's Customer Connection Policy, Customer Contribution and Refund Policy, Procedure for Capital Expenditure Approval and Method for Economic Feasibility Assessment.

3. The Company is also evaluating policy options to support expansion to potential new communities. Details on the Company's plans in this area are documented in Exhibit B1, Tab 3, Schedule 1.

4. The most recent feasibility parameters are used in this evidence, which are based on the 2012 system expansion portfolio and are updated to reflect EB-2012-0054 Decision with Reasons.

Customer Connection Policy

5. The Company uses a portfolio approach to manage the system expansion activities and ensures that the required profitability standards are achieved at both the individual project and the portfolio level. Investment Portfolio and Rolling Project Portfolio are two Board prescribed portfolio approaches and are discussed on page 3 of this exhibit.

Witnesses: F. Ahmad
P. Squires

6. The Company manages to achieve a Profitability Index ("PI") of greater than 1.0 for both portfolios as required by the Board under EBO 188.

7. The minimum PI required for individual projects is 0.80. For projects with a PI less than 0.80, the customer shall be required to pay a Contribution-in-Aid-of-Construction ("CIAC") to bring the project up to the required PI level.

8. Customers connecting to the existing mains are provided, at no cost, with a service connection up to a maximum of 20 meters. Any service length beyond 20 meters is charged to the customer at a rate prescribed in Rider G.

9. The length of service for feasibility assessment is measured from the customer property line to the meter.

10. Requests for exceptions to the minimum PI must be authorized by the Manager, Customer Portfolio and Policy.

11. During construction and operation of each project, the Company will comply with the "*OEB Environment Guidelines for HydroCarbon Pipelines and Facilities in Ontario*".

<u>Customer Contribution and Refund Policy</u>

12. CIAC may be obtained for projects having a negative Net Present Value ("NPV") or a PI less than 1.0. The contribution should be sufficient to bring the project PI up to a viable level as assessed by the Customer Portfolio and Policy group from time to time. Harmonized Sales Tax ("HST") is added to contribution payments.

13. Where the use of a proposed facility is dominated by a single large volume customer, it is considered a dedicated facility for CIAC purposes. The dominant customer may be required to pay a contribution to result in a project NPV of zero or a PI of 1.0. Contribution amounts are subject to added HST.

14. Refunds of CIAC may be requested when the actual customer count on the system expansion exceeds the original forecast. For general service customers, these refunds are processed at the end of five years from the date of construction. The system expansion project is then re-evaluated with the actual customer count to determine a revised contribution that is required to bring the NPV to the original targeted level. The difference between this and the actual contribution paid by customers is the total amount to be refunded. Refunds are made based on the proportionate contribution of the customers.

15. Refunds for large volume customers will be determined based on a re-evaluation of the system expansion project taking into consideration extra investment and additional load brought on within five years to the specific piece of main constructed to serve the initial customer(s).

16. These refunds are made only for the specific piece of main put into service and no refunds are payable for customers added downstream of this piece of main. No interest is payable, and only customers who made a contribution are eligible for a refund. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which refund is being claimed. If the customer moves, he or she is responsible for notifying the Company of the new address. Records of contributions are maintained by the Business Performance group at Enbridge.

Witnesses: F. Ahmad
P. Squires

System Expansion Portfolios – Accountability

17. Investment Portfolio: The Company evaluates all system expansion projects in a test year and ensures they achieve a portfolio PI threshold of 1.1. All new customers attaching to new and existing mains are included in this portfolio. The Manager, Customer Portfolio and Policy is accountable for ensuring that the required PI threshold is achieved.

18. Rolling Project Portfolio ("RPP"): The Company also maintains a rolling 12-month distribution expansion portfolio including the cumulative result of project-specific Discounted Cash Flow ("DCF") analyses. The RPP does not include customer attachments from existing mains constructed in prior years. The Company maintains RPP at a PI level greater than 1.0 and the Capital Management group in Finance is accountable for maintaining this level.

Procedure for Capital Expenditure Approval

19. Enbridge's procedure for obtaining management approval to make a capital expenditure for distribution system expansion is known as the Authorization for Expenditure ("AFE"), and is outlined in the AFE manual. A system expansion project is typically initiated by a Regional Customer Connections Field Representative, who identifies potential new customers. He or she will assess the required amount of plant additions to provide service and will initiate an AFE for approval.

20. A feasibility calculation is required with an AFE, which assesses the estimated revenue and benefits of attaching these new customers against the cost of serving them. The Capital Project Feasibility ("CAPF") program is an IT tool used for evaluating all projects except for Large Volume Customer additions. Large volume

projects are separately evaluated by Enbridge's Investment Review group with inputs from the special project group. All calculations related to project feasibility assessment are attached to an AFE as part of the approval process.

21. The Customer Connections representative inputs information on plant requirements, customer additions and timing, and volumetric data for Subdivision/Residential and Commercial/Industrial connections. For large-volume connections, the inputs are completed by the Investment Review group.

22. All AFEs are approved by the appropriate departmental managers, directors, VPs and President as set out in the workflows. In addition, all AFEs are approved by the Capital Management group in Finance and the workflows are monitored and managed by this group as well to ensure the appropriate individuals are in the workflow for approval of an AFE. The Group also ensures compliance with the Company's Connection Polices.

<u>Method for Economic Feasibility Assessment</u>

23. This section provides the method used to determine the input parameters including cost and revenues associated with a system expansion project. These parameters are discounted at the Utility's Weighted Average Cost of Capital ("WACC") to perform a DCF analysis. The Economic Feasibility of a project is measured using a NPV and PI.

24. <u>Capital Cost:</u> Budgeted average unit prices are used to estimate capital cost for mains and services based on the required pipe size and ground conditions. This procedure is used to develop capital estimates for all residential, commercial and industrial connections.

25. For large volume connections (i.e., above 340 000 m^3 annual consumption), field estimates are used to estimate mains and service cost.

26. If a main is oversized to meet future growth potential, it may be re-priced at the size required to meet customers' load requirements for feasibility calculations. The actual cost of the main must be shown on the AFE.

27. An incremental overhead allowance is added to the cost of mains and services and is incorporated in the CAPF program for feasibility analysis.

28. <u>Consumption and Revenue:</u> For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split or two-storey). The CAPF program calculates customer revenue based on consumption levels input by the local Customer Connections representative.

29. A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

30. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board Approved revenue rates.

Witnesses: F. Ahmad
P. Squires

31. Customer Attachment and Revenue Horizon: The maximum customer attachment horizon for regular residential, commercial and industrial connections is 10 years. The revenue horizon is 40 years from the in-service date of the initial mains.

32. For large volume customers, the customer attachment horizon is 10 years. The maximum revenue horizon is 20 years from the customers' initial service date if this is a reasonable expectation.

33. Marginal Operating and Maintenance ("O&M) Expenses: According to the most recent feasibility parameters, the incremental O&M cost for adding residential connections is estimated to be $70.13 per customer.

34. For commercial and industrial connections, the incremental O&M cost is $196.92 per customer.

35. For large volume connections, incremental O&M is determined based on the average annual expense for various rate classes except for rate 125 and is shown in Table 1. For Rate 125 customers, marginal O&M is determined on a case by case basis.

Table 1
Marginal O&M Expense per Customer

Rate Class	R9	R110	R115	R135	R145	R170	R300
Marginal O&M per customer	$4,103	$6,152	$7,685	$4,089	$4,921	$5,702	$5,679

Witnesses: F. Ahmad
P. Squires

36. Gas Costs: Gas costs are based on the Weighted Average Cost of Gas ("WACOG") less the commodity component. Currently the WACOG (excluding commodity) is $.0821/m^3 for conventional heating and water heating loads at residential, commercial and industrial facilities.

37. For large volume connections, gas costs are based on the customer's load profile characteristics which will typically warrant a customized gas cost calculation consisting of four components including: 1) Unbilled and Unaccounted for Gas ("UUF"), 2) transportation, 3) annual storage and 4) peak day delivery. The Investment Review group calculates gas cost based on the customers' monthly volumes, contract demand and service requirement (Western or Ontario). All gas costs include UUF, but only Western contracts include transportation costs. The customers' load profile dictates the amount of load balancing, storage, and peak day costs/credits are included in gas costs. Firm customers will incur peak day costs, while interruptible customers will receive peak day credits. UUF and transportation costs will be applied to the customers' load, storage costs to the customers' stored gas, and peak day costs to the customers' peak day storage requirement if the customer is firm. Peak day credits will be applied to interruptible customers' average daily volume. The formula used for calculating amounts of stored gas and peak day storage requirements are included with the table of costs found in Table 2.

38. The interruptible gas cost categories are: (a) Rate 145 customers with a minimum 16 hour curtailment notice; and (b) Rate 170 customers with 4 hours curtailment notice.

Witnesses: F. Ahmad
P. Squires

Table 2

Gas Cost for Large Volume Customers

		UUF ($/m^3)	Transportation (Western Only) ($/m^3)	Annual Storage ($/m^3)	Peak Day Delivery ($/m^{3}d)
		Annual load	Annual load	Stored gas[1]	Excess on peak day over average daily
Firm	Rates 100, 110,115, 135				
	a) Volume				
	b) Cost				
	Rates 100,110,115	0.00096	0.05870	0.01055	1.13250
	Rate 135	0.00096	0.05870	0.00000	(1.34821)[3]
Interruptible	Rates 145 and 170				
	a) Rate 145 with 72 hour curtailment	0.00096	0.05870	0.01055[2]	(1.34821)[3]
	b) Rate 145 with 16 hour curtailment	0.00096	0.05870	0.00770[2]	(0.23048)[3]
	c) Rate 170[4]	0.00096	0.05870	0.00770[2]	(0.23048)[3]

1 (Volume from November to April/181 days – Annual Load/365 days)*181 days
2 Applied to uncurtailed volumes.
3 Applied as a credit based on the customers' average daily volume
4 If Enbridge Gas Distribution is restricted in utilizing its interruption rights a custom calculation should be performed by the Investment Review group.

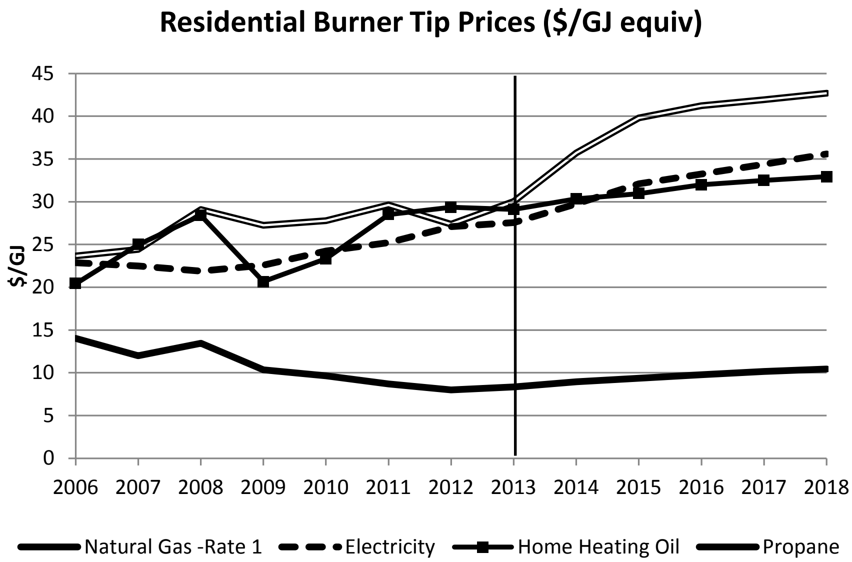
COMMUNITY EXPANSION

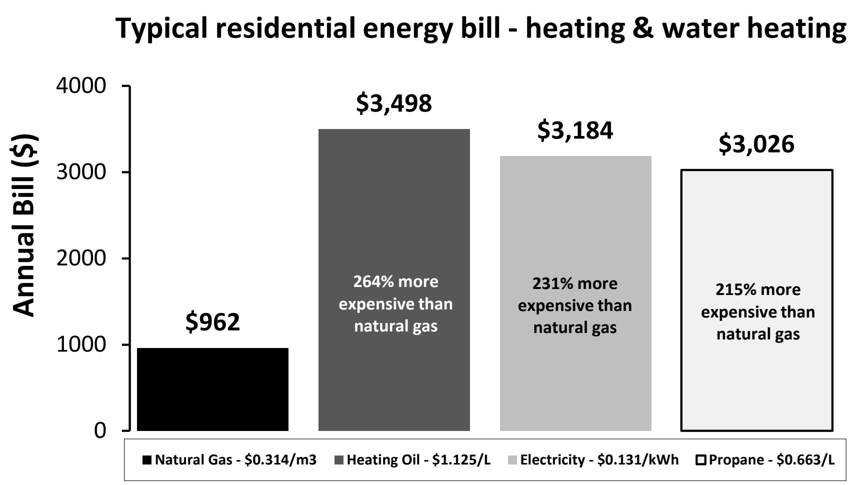
Expansion Of The Natural Gas Distribution System

1. Enbridge Gas Distribution ("EGD") is planning to file a Community Expansion proposal within late 2013 to early 2014. The purpose of this evidence is to provide context in regards to the considerations and benefits of such a proposal.

2. Currently there are a large number of municipalities that continue to benefit from past expansion of the natural gas system. Recognizing the benefits that natural gas service provides, demand from other Ontario municipalities to extend the natural gas distribution system to their areas has grown significantly in recent years. Municipalities view access to clean and affordable natural gas as a key component in improving their competitiveness and ability to attract and retain businesses. Other benefits such as improved home and property values put system expansion at the top of the list of priorities for their community.

3. In addition to the many customer benefits that access to natural gas provides, natural gas has consistently provided a pricing advantage compared to electricity, propane and home heating oil. This pricing advantage is illustrated in the charts shown below. The price gap between these other energy sources has widened considerably over the last five years to the point where natural gas is, in many cases, 1/3rd the cost for home heating and water heating. The available savings to prospective new customers is the major factor driving demand from new communities.





Note: Natural gas prices are based on rates in effect as of April 1, 2013. Oil and propane prices are based on the latest available retail prices. Electricity rates based on Toronto Hydro rates as of November 1, 2012 and do not include the Ontario Clean Energy Benefit**. Costs have been calculated for the equivalent energy consumed and include all service, delivery and energy charges. HST is not included.**

4. In response to this ongoing demand from potential customers, Enbridge is assessing different alternatives to expand the gas distribution system and bring the benefits of natural gas to new communities. Enbridge expects that the level of investment and infrastructure required per customer will be quite different from

historic norms. Finding ways to connect customers in these communities will require the Company to consider alternative solutions that address the issue of financial feasibility.

5. Most system expansion projects require large capital investments which under some circumstances leaves them financially unfeasible under the current system expansion guidelines prescribed by the Board under EBO 188. Generally, these projects require a capital contribution from the customer to ensure there is no long-term rate impact on existing customers.

6. The Company is in the early stages of examining a variety of options to enable flexibility in the way that customer needs could be met. For example, alternative solutions to recover the revenue shortfall inherent in infeasible projects could be implemented, while simultaneously retaining enough economic benefit that new customers will see meaningful net reductions in their energy costs.

Conclusion

7. Many customers, in a great number of communities, have benefited from the direct and indirect benefits that have resulted from past expansion of the natural gas. It is important to ensure that tools and mechanisms that promote system expansion to new communities are made available to prospective customers, and that these tools don’t remain static in an environment that continues to change over time.

Witnesses: T. MacLean
D. McIlwraith

2014 to 2018 CAPITAL BUDGET OVERVIEW

1. The purpose of this evidence is to provide the Ontario Energy Board (the "Board", or the "OEB") with an Overview of Enbridge Gas Distribution's ("Enbridge", "EGD" or the Company") detailed Capital Budget for the years from 2014 to 2016. As described in Exhibit A2-1-1, the Company has used its 2016 Capital Budget as the basis for forecasting its spending requirements for each of 2016, 2017 and 2018. While details of the components of the Capital Budget are found in the balance of the B2 series of exhibits, this Overview sets out how and why the Company has chosen to set out details of a three year Capital Budget and explains the main components of the Capital Budget.

2. The Company's forecast capital expenditures for 2014 to 2016 have been identified as the outcome of a lengthy budgeting process that commenced with the Board approval of the 2013 rates case settlement (EB-2011-0354), followed by a lengthy Company process to identify, evaluate and determine its capital spending needs in coming years. The budgeting process has ensured that Enbridge's 2014 to 2016 Capital Budget reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. The 2016 Capital Budget reflects the level of spending required in 2016, and a base level of spending in 2017 and 2018.

3. What has become clear through the budgeting process is that the Company's necessary level of capital spending is higher than in past years, and the spending requirements become unacceptably unpredictable when one looks out further than three years. As explained in Exhibit A2-1-1, it is this combination of high capital spending requirements and uncertainty in the longer term that have driven Enbridge to request approval of its Customized IR plan.

Witnesses: J. Sanders
P. Squires

4. The Company's Capital Budget forecast for 2014 to 2016 indicates required capital expenditures of $682.3 million in 2014, $832.0 million in 2015 and $450.0 million in 2016. These budgets are substantially higher than prior year budgets. There are two main reasons for this. First, there are very high levels of spending associated with three major projects which the Company must undertake in the next three years. Second, there are substantial cost pressures associated with a higher level of required System Integrity and Reliability spending.

5. This Overview evidence sets out the main components of the 2014 to 2018 Capital Budget, including the process used to arrive at that budget, under the following topic headings:

   A. A summary of Enbridge's forecast capital expenditures over the period of 2014 to 2016,

   B. An explanation of the main drivers of the Capital Budget for 2014 to 2016,

   C. A description of the budgeting process that identified the necessary expenditures that form the Capital Budget,

   D. Explanation of the outcomes from the Capital Budget process,

   E. Explanation of how management incorporated productivity in the proposed Capital Budget for 2014 to 2016,

   F. Explanation of year over year variances in the 2014 to 2016 Capital Budget, and

   G. Explanation of why and how the 2016 Capital Budget is used as the basis for the 2017 and 2018 Capital Budget.

A. Summary of the Capital Budget 2014 - 2016

6. Table 1 provides a summary view of the planned capital expenditures for the Company, totaling $682.3 million in 2014, $832.0 million in 2015 and $450.0 million in 2016. These amounts are categorized in a standard summary view of the Capital Budget, as provided in previous applications.

Table 1
Summary of Capital Expenditures

($Millions)	Col 1 Board Approved Budget 2013	Col 2 Forecast 2014	Col 3 Forecast 2015	Col 4 Forecast 2016
Customer Related Distribution Plant	123.0	119.0	126.8	137.1
NGV Rental Equipment	0.3	3.4	3.6	3.7
System Improvements and Upgrades	192.8	243.2	247.8	242.2
General and Other Plant	47.6	56.3	52.7	48.4
Underground Storage Plant	22.4	21.9	15.7	10.5
Sub total "Core" Capital Expenditures	386.1	443.8	446.6	441.9
Work and Asset Management System (WAMS)	0.5	36.3	25.7	8.1
Leave to Construct - Major Reinforcements	63.3	202.2	359.7	-
Total Capital Expenditures	449.9	682.3	832.0	450.0

7. The Company will use the term "Core Capital" to include all capital spending, except for three identified major projects: the GTA and Ottawa Reinforcements and the Work and Asset Management Project (WAMS). The "Core Capital" term essentially captures the spending amounts that were included within the 2013 Board Approved Capital amount (after taking into account, as seen in Table 1 above, that there was $0.5M of initial WAMS project spending included within the 2013 Board Approved Capital amount).

Witnesses: J. Sanders
P. Squires

8. Table 2 provides a standard detailed schedule of the proposed Capital Budgets for 2014 to 2016, as compared to the 2013 Board approved Capital Budget amount of $386.6 Million.

Table 2

COMPARISON OF UTILITY CAPITAL EXPENDITURES
2013 BOARD APPROVED BUDGET AND 2014 -2016 FORECASTS
(EXPRESSED IN $MILLION)

		Col. 1	Col. 2	Col. 3	Col. 4
Item No.		Board Approved Budget 2013	Forecast 2014	Forecast 2015	Forecast 2016
A.	Customer Related				
1.1.1	Sales Mains	44.6	39.6	42.1	49.1
1.1.2	Services	68.1	69.0	73.7	76.3
1.1.3	Meters and Regulation	10.3	10.4	11.0	11.7
1.1.4	Customer Related Distribution Plant	123.0	119.0	126.8	137.1
1.1.5	NGV Rental Equipment	0.3	3.4	3.6	3.7
1.1	TOTAL CUSTOMER RELATED CAPITAL	123.3	122.4	130.4	140.8
B.	System Improvements and Upgrades				
1.2.1	Mains - Relocations	27.5	28.6	24.9	26.0
1.2.2	- Replacement	71.0	105.6	94.2	82.5
1.2.3	- Reinforcement	27.0	21.3	31.6	18.1
1.2.4	Total Improvement Mains	125.5	155.5	150.7	126.6
1.2.5	Services - Relays	17.3	29.8	34.5	52.1
1.2.6	Regulators - Refits	9.7	9.8	10.0	10.1
1.2.7	Measurement and Regulation	24.3	31.5	34.1	32.6
1.2.8	Meters	16.0	16.6	18.5	20.8
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	192.8	243.2	247.8	242.2
C.	General and Other Plant				
1.3.1	Land, Structures and Improvements	7.8	12.9	11.2	6.8
1.3.2	Office Furniture and Equipment	1.6	4.6	4.7	4.4
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	4.8	4.6	4.7	4.7
1.3.4	Tools and Work Equipment	1.4	1.5	1.5	1.5
1.3.5	Computers and Communication Equipment	32.0	32.7	30.6	31.0
1.3	TOTAL GENERAL AND OTHER PLANT	47.6	56.3	52.7	48.4
D.	Underground Storage Plant	22.4	21.9	15.7	10.5
E.	SUBTOTAL "CORE" CAPITAL EXPENDITURES	386.1	443.8	446.6	441.9
F.	Work and Asset Management System (WAMS)	0.5	36.3	25.7	8.1
G.	SUBTOTAL CAPITAL EXPENDITURES	386.6	480.1	472.3	450.0
H.	Leave to Construct				
1.7.1	Ottawa Reinforcement	44.0	5.1	-	-
1.7.2	GTA Reinforcement	19.3	197.1	359.7	-
1.7	TOTAL LEAVE TO CONSTRUCT	63.3	202.2	359.7	0.0
I.	TOTAL CAPITAL EXPENDITURES	449.9	682.3	832.0	450.0

Witnesses: J. Sanders
P. Squires

9. The first step in the budget process that led to the 2014 to 2016 Capital Budget was the finalizing of the 2013 capital budget to match the necessary capital needs of the business to the 2013 Board approved settlement amount of $386.6 Million (note that the Ottawa and GTA Reinforcement projects were outside of the $386.6 Million amount). In conducting the 2013 budget process, the Company determined that the necessary business expenditures and costs for 2013 were greater than the Board approved settlement amount. The Company is not seeking any recoveries in the Customized IR plan proposal for the additional capital spending in 2013 (nor the spending above forecast levels in 2012). The Company expects to bring forth in the Rebasing Rates Application any amounts of additional Capital spend for 2012 and 2013.

10. Based on the learnings from the 2013 budgeting process, including the recognition of increasing spending requirements for safety and integrity projects, the Company undertook a "Capital Budget Refresh" process to understand its capital spending needs for the period 2014 to 2018. That process, which involved several iterations of scrutinizing and prioritizing proposed capital spending, ultimately resulted in the three year detailed Capital Budget.

11. As explained within the updated evidence in the A2 series of exhibits, Enbridge has used the 2016 Capital Budget to represent its 2017 and 2018 capital spending requirements within the Allowed Revenue amounts for 2017 and 2018. Enbridge has made this change to the Customized IR plan to address the expectation that the Company will set Allowed Revenue amounts for all five years of this Customized IR term in this proceeding, and not revisit capital spending requirements midway through the term. While Enbridge is not currently able to specifically forecast all elements of its 2017 and 2018 Capital Budget, the Company believes that the best overall forecast of its capital spending requirements during those years can be seen

in the 2016 Capital Budget. Although some of the detailed spending requirements will change each year, Enbridge expects that the overall capital spending requirements for 2017 and 2018 will be in line with 2016. The one change that Enbridge has made to the 2016 Capital Budget is that, for purposes of 2017 and 2018, the $8 million forecast spending on WAMS has been removed, since that project will have been completed. Therefore, the Capital Budget used for 2017 and 2018 is the same as set out in the "Forecast 2016" column within Tables 1 and 2 above, except that the $8.1 million associated with WAMS is removed, leaving a forecast Capital Budget of $441.9 million for each of 2017 and 2018.

12. Further details about the application of the 2016 Capital Budget to 2017 and 2018 are set out below, in section "G" of this evidence.

13. The Capital Budget as proposed for 2014 to 2016 reflects the continued application of the Company's capitalization policy. In EB-2011-0354, the Board approved Enbridge's continued use of that capitalization policy notwithstanding the transition to US GAAP accounting policies.

14. The proposed overall capital expenditures for 2014 to 2016 represent a significant increase from the 2013 Board Approved Capital amount. The majority of the increase in expenditures can be attributed to three business needs:

- First and most significant is the need for the GTA and Ottawa Reinforcement projects,
- Second, the need for investment in WAMS, and
- Third, is the need for a variety of new and increased work to address System Integrity and Reliability requirements of the Company's distribution

system. It is this need that is primarily driving the increase in Core Capital Spending.

15. Details about the high-level drivers of the Capital Budget for 2014 to 2016 are set out in the next section of this Overview.

B. Main Drivers of the Capital Budget For 2014 To 2016

16. The Capital Budget for 2014 to 2016 is driven by new and ongoing spending requirements. The ongoing requirements include the continuation of historic activities to: (i) maintain the distribution system (including storage), (ii) add new customers, and (iii) maintain the Company's other infrastructure (such as buildings and IT systems). The new requirements relate to: (i) Major Reinforcement projects in the GTA and Ottawa, (ii) a need to implement WAMS to provide primary work and asset management functionality and support the increasing amount of asset-related work, (iii) increasing System Integrity and Reliability work to address identified risks within the Company's distribution system, and (iv) the need to act on increasing relocation work (especially in 2014) that is driven by external third-party projects.

17. The following sections provide information on the main drivers of Enbridge's 2014 to 2016 Capital Budget. The balance of the B2 series of exhibits contains further details about the Company's individual business area capital budgets, including descriptions of projects of $2 million or more, that cumulate to form the overall 2014 to 2016 Capital Budget.

Continuation of Historic Activities and Costs (Business as Usual)

18. The Capital Budget for 2014 to 2016 include a continuation of historic activities that: (i) maintain the distribution system (including storage), (ii) add new customers, and (iii) maintain the Company's other infrastructure (such as buildings

and IT systems); and historic costs such as (iv) departmental labour costs, (v) Capital Overheads (Administrative and General), and (vi) Interest During Construction.

(i) maintain the distribution system (including storage)

19. Within the Capital Budget, the Company will continue to undertake activities that are "keeps the lights on" type of capital work. Examples of these activities that the Company will continue to perform are the code and regulation based Meter Exchange Government Inspection program and the spending on base maintenance activities in the Reinforcements and Relocations areas.

(ii) add new customers

20. From 2009 and 2012, Enbridge's annual customer additions rose from approximately 32,000 to 36,000 new customers per year. Enbridge forecasts this trend to continue for the next few years with the addition of new customers being approximately 38,000 in 2013, 36,500 in 2014, 38,500 in 2015 and 39,500 in 2016. The Capital Budget includes the costs to add the annual forecasted new customers.

(iii) maintain the Company's other infrastructure (such as buildings and IT systems)

21. The Capital Budget includes costs to maintain facilities in a safe state and replacing out of date or end of life IT systems through the period of 2014 to 2016. In finalizing the necessary spending proposed in the Capital Budget, the Company has decided to defer some facilities-related activities, such as replacing aging building facilities.

(iv) Departmental Labour Costs

22. Departmental labour costs are primarily the salaries and employee expenses for the departments within Engineering and Operations. The respective functions of these departments contribute to putting Core Capital activities (Mains, Services and Stations) into service. Examples of these functions include system capacity planning, distribution plant drafting, pipeline inspection, field operations, customer attachment and records management.

23. The Capital Budget process reviewed each department and assessed staffing needs for the period of 2014 to 2016. Overall, the Company expects to deliver its Core Capital spending without adding additional Departmental Labour costs. The costs going down from 2013 levels and being maintained below 2013 levels for the period of 2014 to 2016 reflects that the Company expects to replace staff that have left through natural attrition with staff that have lower salaries. Through the period of 2014 to 2016 management expects turnover of employees to be as much as 100 employees annually. By not adding departmental labour costs for base programs, the Company is committing to accommodating any additional work in these programs by finding efficiencies in operations between these departments.

24. The following Table 3 sets out the amounts of Departmental Costs from 2014 to 2016 and are included in Tables 1 and 2.

Table 3
Departmental Labour Costs 2013 - 2016
($,000)

		2013 Budget Capitalized Departmental Labour Costs	2014 Forecast Capitalized Departmental Labour Costs	2015 Forecast Capitalized Departmental Labour Costs	2016 Forecast Capitalized Departmental Labour Costs
B1-2-1	**Total Departmental Labour Expenditures**	76,563	74,843	73,428	75,551

Witnesses: J. Sanders
P. Squires

(v) Capital Overheads (Administrative and General Costs)

25. Capital Overheads are recognized as Administrative and General Costs (A&G) and are a function of Operations and Maintenance expenses. The A&G costs represent the common services that support capital activities. As per Board approved methodology, specific categories of Operations and Maintenance expense are capitalizable by applying specific percentages (i.e.: Human Resources, Information Technology and Corporate Departments).

26. A&G is charged to Distribution plant; Storage plant and IT asset classes and allocated to each area as a percentage of that areas cost to the total Distribution Plant, Storage Plant and IT costs. Capital Overheads increase slightly over the period of 2014 to 2016 from their 2013 Budget. The increase between 2014 and 2013 is reflective of the slight increase in Corporate Department expenses and the increases in 2015 and 2016 reflect the increases in O&M salaries and expenses. Capital Overheads represent approximately 8% of the annual Core Capital Budget.

27. The following Table 4 sets out the amounts of A&G amounts within the Capital Budget from 2014 to 2016 and are included in Tables 1 and 2.

Table 4
Capital Overheads (A&G) Costs 2013 - 2016
($,000)

		2013 Budget Capital Overheads (A&G)	2014 Forecast Capital Overheads (A&G)	2015 Forecast Capital Overheads (A&G)	2016 Forecast Capital Overheads (A&G)
B1-2-1	Total Capital Overheads (A&G) Expenditures	33,602	35,500	36,440	37,140

(vi) Interest During Construction

28. Interest During Construction (IDC) is the recoverable amount of interest that the Company must spend in order to fund its capital initiatives. The calculation of IDC

is a function of work in progress balances. This is applicable to pipeline construction, storage plant construction and software applications that are in progress and not yet used or useful.

29. The following Table 5 sets out the amounts of IDC amounts within the Capital Budget from 2014 to 2016 and are included in Tables 1 and 2.

Table 5
Interest During Construction (IDC) Costs 2013 - 2016
($,000)

		2013 Budget Interest During Construction (IDC)	2014 Forecast Interest During Construction (IDC)	2015 Forecast Interest During Construction (IDC)	2016 Forecast Interest During Construction (IDC)
B1-2-1	**Total Interest During Construction (IDC) Expenditur**	**5,356**	**8,400**	**9,251**	**7,399**

30. The forecast costs of Departmental Labour, Capital Overheads (A&G) and IDC are included and allocated across the major accounts set out within Tables 1 and 2.

GTA and Ottawa Reinforcements

31. The proposed GTA and Ottawa Reinforcements address critical distribution infrastructure requirements in the Greater Toronto Area and Ottawa. The Company has outlined the needs and benefits of these projects in its Leave to Construct applications (EB-2012-0099 and EB-2012-0451).

32. The Ottawa Reinforcement project is intended to increase the capacity of the Ottawa area distribution system to meet existing and forecast loads as well as to provide additional security of supply and operational flexibility. The Ottawa Reinforcement project has been approved through the Board's Decision on the Leave To Construct application, issued on November 29, 2012.

33. The GTA Reinforcement project is intended to maintain system safety and reliability through enabling pressure reduction on several key pipelines in the Greater Toronto Area. The project is also intended to support diversification of supply. The GTA Reinforcement Leave To Construct application is currently being heard by the OEB.

34. The forecast costs of these Major Reinforcement projects are set out separately within Tables 1 and 2.

Work and Asset Management System (WAMS)

35. The proposed Work and Asset Management System (WAMS) is a requirement for the future operations of the Company servicing our customers. The WAMS project is fully described in Exhibit B2-6-2. The need for this project stems from technology drivers and the need to support primary work and asset management functions.

36. The primary driver is the coming end of the Accenture Services Agreement which was part of the EnVision Project that the Board approved in its 2004 decision of RP-2003-0203. The Company has decided that a more cost effective solution to the services approach that currently provides Work and Asset Management services would be to implement an in-house IT system. Timing is also driven by technology obsolescence of the decade old solution. It is also recognized in the industry that the area of asset management information systems has evolved substantively since 2004. WAMS will be the primary system for creating and tracking work requests and transactional asset information related to functions such as construction, maintenance, service, etc. Aligning asset related work with other work activities will provide an opportunity to package activities in an efficient

manner. An example of the packaged approach would be scheduling an AMP Fitting replacement to coincide with a leak survey or service relay.

37. Another driver is the need for the Company to meet more stringent safety and reliability standards, which necessitates more flexible information technology.

38. Finally, the WAMS project will support the proposed performance measurement tracking and reporting on productivity over the Customized IR Plan term, including productivity of outside partners.

39. These business drivers have established a priority for the Company to implement the WAMS Program. Over the next two years this project will source and implement technology that will enable Enbridge to continue to operate its core functions, and implement systems that complement the Company's holistic asset management approach.

40. The forecast costs of the WAMS project are set out separately within Tables 1 and 2.

System Integrity and Reliability Activities

41. The Company has identified that a continuation of increased activities and expenditures associated with System Integrity and Reliability is necessary for the period of 2014 to 2016 and beyond. The Company has also determined that the System Integrity and Reliability costs for 2017 and 2018 are uncertain, but very likely to be as much or more than the corresponding costs in 2016.

42. From November 1, 2012 the Company is obligated to implement and operate a fulsome program as a natural gas distributor in the province of Ontario. The increase in activity and expenditures for System Integrity and Reliability which led

to an increased level of spending starting in 2011 can be attributed to the following items:

- Recent Events: safety incidents at utilities in the United States
- Changes to regulations in both the United States and Ontario
- Enbridge's ongoing review of processes and decision criteria to maintain a safe distribution system

43. The focus on integrity management programs has been heightened as a result of safety incidents at natural gas utilities in the United States. One such event was the September 2010 San Bruno pipeline rupture and ignition in California. The event resulted in the death of eight individuals, the destruction of 38 homes, and injury to several additional individuals and damage to several other properties in the area.

44. As a result of the San Bruno incident, regulation, standards and legislative obligations for natural gas utilities in the United States were amended to be more stringent with respect to integrity management of distribution systems.

45. The November 1, 2012, the Technical Standards and Safety Authority ("TSSA") Code Adoption Document (FS-196-12) requires companies to produce an Integrity Management Program to maintain a safe and reliable Distribution System. This regulation includes the Document Amendment clause 12.10 (of the Canadian standards Association Z662):

> 12.10.16: Operating companies shall establish effective procedures for managing the integrity of pipeline systems with an MOP less than 30% of SYMS (Distribution Systems) so that they are suitable for continued service, in accordance with the applicable requirements of clause 3.2 of CSA Z662-11.

46. For Enbridge, this means that all of the operating distribution assets will now need to be included and managed within an effective System Integrity and Reliability set of activities. As per clause 3.2 of CSA Z662-11 Pipeline System Integrity Management Program, this program must assess potential risks, identify steps to reduce these risks and monitor the results of the risk reduction projects or program. As per clause 10.3.10 of TSSA's November 1, 2012 Oil and Gas Systems Code Adoption Document, the Integrity Management Program shall include:

- a management system;
- a working records management system;
- a condition monitoring program, and
- a mitigation program

47. Management has taken its responsibility under the recent TSSA code change and more stringent landscape in the United States as an important change to its legislated obligations and expectations on how it manages the distribution system. Management has interpreted the code change as a requirement to proactively assess risks, propose remediation, refurbishment and replacement of the distribution system, when and where necessary, to prevent system failures.

48. Within Enbridge's proposed Integrity Management program expenditures for 2014 to 2016, examples of management decisions include:

    A. the expenditures for In-Line Inspections ("ILI") of pipelines above 20% of the Specified Minimum Yield Stress ("SMYS") and the Maximum Operating Pressure ("MOP") Verification Program;

B. adopting a proactive replacement strategy towards replaceable technology such as Compression Couplings or AMP Fittings rather than monitoring their operation and replacing after the failures have occurred; and

C. replacing critical operating assets such as specific components of Gate and District Stations (up to and including the entire station) rather than extending the active use of these assets beyond the end of their useful life through the use of Operations and Maintenance budgeted activities.

49. As set out within the Asset Plan (filed at Exhibit B2, Tab 10, Schedule 1), the Company expects to continue these activities within 2017 and 2018.

Externally Initiated Capital Projects

50. A further driver of incremental capital spending requirements in the coming years is the expected increase in relocation requirements resulting from third-party infrastructure projects, such as transit and the Pan Am games.

51. The main driver for the proposed increase to these costs is projects from government organizations such as:

- the 2015 Pan American Games,
- Toronto Transit Commission (“TTC”), and
- MetroLinx

52. These externally driven infrastructure projects lead to requirements for pipeline replacements or relocations. While relocation activity is not new, the level of expected activity in the coming years is a substantial increase from past experience.

The forecast cost increases can be seen within the Mains-Relocations line at Table 2, above.

C. Capital Budgeting Process

53. To understand and evaluate the Company's Capital Budget, it is useful and informative to look at how the budget was created. As explained below, the lengthy and rigorous process that led to this Capital Budget has ensured that the budget is set at a level that reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. Savings attributable to productivity and efficiency initiatives are included within the Capital Budget amounts.

54. The Company commenced the capital budgeting process that led to the 2014 to 2016 Capital Budget in November of 2012. The first step in the process was to align the 2013 Board-Approved Capital Budget of $386.6 million with the Company's spending requirements for 2013. That step led to a realization that complete alignment was not possible, because spending requirements for 2013 exceed that level. However, for the purpose of this Application, Enbridge has set out its 2013 Capital Budget to align with the Board-Approved Capital Budget amount. As noted above, to the extent that Enbridge spends above that level, it will not seek recovery until its Rebasing Application.

55. Immediately after the 2013 Capital Budget was set, the Company proceeded with its "Budget Refresh" process to update its forecasts of capital spending for 2014 to 2018. This began with a "Bottom-Up" list of business needs, and then proceeded through several iterations where proposed projects and spending were presented to and scrutinized by management and direction was given to make changes to the Capital Budget. Through a lengthy iterative process, Enbridge arrived at a three

year Capital Budget for 2014 to 2016, having determined that capital expenditures for 2017 and 2018 were too speculative to be included.

Inputs to the Capital Budget

56. As noted, the capital budget process began with a "Bottom Up" list of capital spending requirements for 2014 to 2018. There were a number of inputs into the creation of this "grassroots" budget, as described below.

(i) Asset Plan

57. The Company's long range distribution system planning tool, the Asset Plan, provides a 10 year view into customer growth, potential reinforcements, system integrity and reliability requirements, relocation projects and major reinforcements. The Asset Plan represents an information vehicle for Enbridge management to use for future planning purposes. The 2013-2022 Asset Plan is filed at Exhibit B2, Tab 10, Schedule 1.

58. The Asset Plan is an ever-evolving document, to reflect the Company's most current understanding of its distribution assets. While the actual 2013-2022 Asset Plan document filed in this case was not completed at the time that the Capital Budget process began in late 2012, the updated identification of the Company's asset requirements (which forms the basis for much of the Asset Plan) had been completed by that time. That information was used as an input into the creation of the "Bottom Up" budgets used at the outset of the Capital Budget process.

(ii) GTA and Ottawa Reinforcement Projects and WAMS

59. The GTA and Ottawa Reinforcements and WAMS project had all been identified as necessary projects by the time that the Capital Budget process began. Each of these projects has been subject to separate budgeting processes, and the outputs

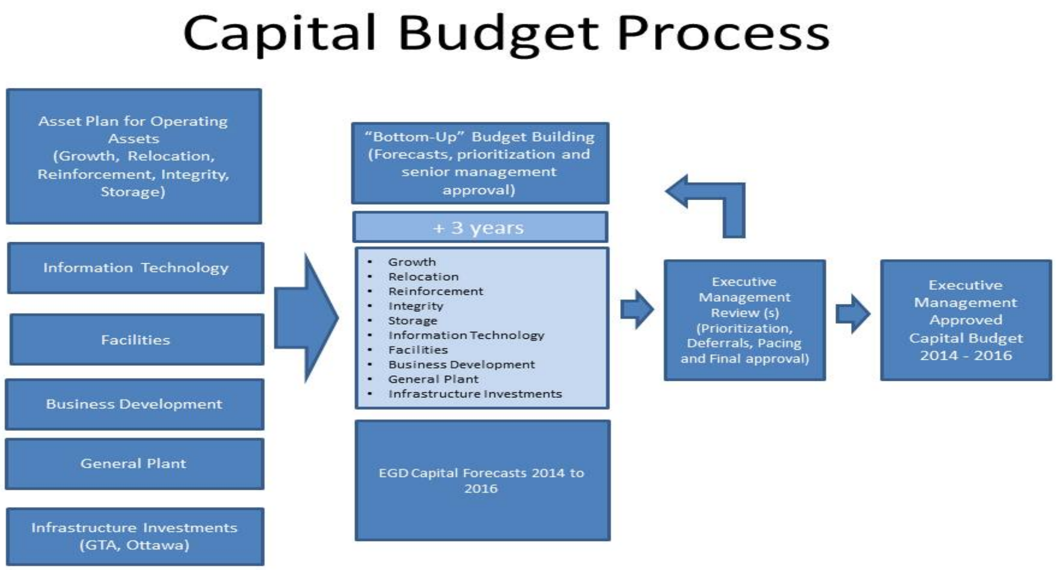
of those project specific reviews were used as inputs into the Capital Budget process.

(iii) All Other Inputs

60. The Asset Plan only addresses the Company's distribution asset requirements. Therefore, to determine the capital spending requirements for other aspects of the Company's operations, information was sought and received from additional capital business areas including Information Technology, Gas Storage, Business Development, Facilities and General Plant. That information was an input into the creation of the "Bottom Up" budgets used at the outset of the Capital Budget process.

Steps in the Capital Budget Process

61. Enbridge's Capital Budget for 2014 to 2016 was determined through a lengthy iterative process. Figure 1 below depicts the process flow undertaken by the Company to finalize its Capital Budgets.



62. The process commenced with departments such as Gas Storage, Information Technology, Facilities and Business Development providing their "Bottom-Up" capital needs. The Asset Plan was used as an input for the Operations and Planning, Integrity and Engineering departments "Bottom-Up" capital needs.

63. After the initial "Bottom-Up" Capital Budget was created, the Company proceeded with an intense process to scrutinize each proposed expenditure. The process was established as a Company priority and included all departments and associated capital decision makers. The objective was to define the amount of necessary capital expenditures required to ensure the utility meets its commitments to its customers and its regulators, including spending necessary to meet the growth, safety and operational requirements of the business. The ultimate goal of this exercise was to ensure that the capital expenditures within the Capital Budget were limited to the lowest prudent level.

Witnesses: J. Sanders
P. Squires

64. A senior management committee ("Capital Owners Committee") made up of senior representatives of the operating groups within the Company, as well as Finance and Regulatory, conducted peer reviews and scrutinized the list of expenditures in each cycle of capital forecast. This resulted in changes to the budgets. For each cycle, the output of the Capital Owners Committee was then reviewed by Executive Management who made their own changes. The Executive Management team was made up of Enbridge's President and Vice Presidents.

65. The Capital Budget process went through six review cycles, culminating in Executive Management approval of the final 2014 to 2016 Capital Budget. Table 3 sets out the timing at which each review cycle was completed.

Table 6

Capital Budget Process Milestone Dates

Date	Iteration
November 1, 2012	2013 Budget Setting Start Date
January 8, 2013	2014 to 2018 Budget Setting Start Date
January 18, 2013	REVIEW 1
February 15, 2013	REVIEW 2
March 22, 2013	REVIEW 3
April 2, 2013	REVIEW 4
April 18, 2013	REVIEW 5
May 21, 2013	REVIEW 6 and Final Capital Budget 2014 – 2016

66. After the first review, it was recognized that many of the System Integrity and Reliability expenditures (along with some other items) had forecasts that were of a variable or uncertain nature. Analysis of the first review showed that the proposed spending pattern was forecasting System Integrity and Reliability activity costs that may not materialize as outcomes of the activity.

67. Executive Management requested a further segmentation of each capital forecast to identify the magnitude of the costs that were certain to be spent and those that were outcome based and therefore difficult to forecast. Each capital expenditure from Review 2 onward was broken out into Variable and Firm costs. The Firm costs category captured costs that were certain and the Variable category represented costs that may or may not materialize, largely based on the outcomes of studies and execution of certain System Integrity and Reliability programs. The Capital Budget Process retained this additional categorization through the remainder of the review cycles.

68. Through the budget review process, the Capital Owners Committee applied a number of criteria to prioritize proposed spending, and determine what items should be retained within each successive version of the Capital Budget, and which items could be altered or removed. The criteria that were applied included the following:

- *Priority*: to identify the need for particular spending within a given year. An example of a change in priority was the decision to delay the Don River Replacement project that is identified in the Asset Plan. Another example is evident in the Facilities budget which had proposed a building expansion to the Company's Kennedy Road facility to accommodate staff who are currently being housed in "portables" in the parking lot.

The final decision of the budget process was to reject building expansion and keep the additional staff in portables.

- *Probability of Spend Occurring*: High, Medium, Low. High Probability ratings were given where there was an 80% to 100% probability of the spend occurring in that year. A Medium Probability rating indicated a 50% to 80% chance and a Low Probability ranking represented a 0% to 50% chance of the project put in service that year. Items of Low Probability are not included within the Capital Budget for a given year, and items of a Medium Probability may have their spending profile changed.

- *Timing of Need*: to determine whether the pacing of the spending can be changed. An example is the Load Shed Program that the Company will continue to undertake in 2014 to 2016. The program adds valves and other assets required to establish isolatable geographic zones within the distribution system. These isolatable zones when established enable the Company to preserve supply to specific customers while neighbouring customers may have their gas supply shut-off in the event of an incident or other business requirement. Through the budget process, a decision was made to slow the pace of implementing the Load Shed Program to a range of 10 to 15 years rather than one of 5 to 10 years. This decision on Timing of Need was based on information that indicated that a longer period of implementation would not adversely increase the risk to Customers being supplied with natural gas.

- *Alternative to Need*: Review of other choices including O&M maintenance. For example, under the System Integrity and Reliability activities, Gate Stations Program, the Gas Preheat System Risk Mitigation project conducted several alternatives to need analysis. The proposed program includes the removal, replacement and testing of the oldest heat exchanger in the system. It also includes the retrofit of the next two oldest heat exchangers with actuated valves on the heat exchanger and glycol loop of the preheat system. Alternatives that were examined included doing nothing, replacing all heat exchangers, just replacing the oldest heat exchangers.

- *Financial Analysis*: Review of Capital and O&M cost interaction, historical trends where applicable, unit cost rates etc. An example was confirmation of a decision to install remote electronic pressure sensing devices to paper chart recorders and provide real-time pressure information to a central control centre. The capital costs of this initiative were confirmed to be less than the expected long-term O&M savings arising from no longer having to operate paper chart recorders and maintain and interpret the paper charts that had been produced.

- *Productivity*: Where applicable, incorporate actions to “get more work for same unit cost”. An example is the proposed capital budget for Customer Related work which shows reductions in the cost to add new customers. This is a result of a determination that the Company can find ways to save money in its actual average cost to add a new customer, as compared to those costs in 2012. Further discussion of the productivity savings within the 2014 to 2016 Capital Budget is set out below.

- *Firm vs. Variable*: as described above.

69. These criteria allowed evaluation of each expenditure by several angles. The multiple angles of examination confirmed to management that the final proposed expenditure represented the lowest reasonable cost for the necessary activity.

70. The final Capital Budget review cycles examined the proposed capital expenditures by year, applying the criteria above to evaluate each capital expenditure. Executive Management provided direction and decisions through each review cycle and continued until they were fully satisfied that the Capital Budget had reached the lowest prudent level.

D. Results of the Capital Budget Process

71. There were three main outputs from the Capital Budget Process.

72. First, the identification of capital spending requirements in excess of historical levels led Enbridge to determine that it required a different IR plan from its 1st Generation IR plan. The discussion of why an "I-X" model is not appropriate is set out in a number of places within the A2 series of exhibits.

73. Second, the identification of a large amount of uncertain spending, especially in the years beyond 2016, led Enbridge to determine that it could only create a three year Capital Budget at this time. This led to the Customized IR plan as originally filed.

74. Third, the key output from the Capital Budget Process was the creation of a three year budget that reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. Through the rigour of the Capital Budget Process, more than $180 million was removed from the originally submitted "Bottom Up" grassroots budgets.

Decision to Proceed with a Three Year Capital Budget

75. The Company had gone through three Capital Budget Review cycles at which time a decision was made to change the budgeting time frame from a five year period ending in 2018 to a three year period of 2014 to 2016.

76. At a high level, the key information that drove the reduction in the term from five years to three years was the significant variability in capital forecasts after 2016. The variability was being driven by two primary issues: (i) uncertainty with System Integrity and Reliability program outcomes; and (ii) uncertainty with externally initiated projects. The amounts in the capital budget forecasts had variability in the range of $50 to $100 million per year of additional capital costs.

77. The decision to create a three year budget was seen to be consistent with the fact that the Company's capital spending requirements over the 2014 to 2016 period will be quite different from future years, because of the need for several major projects (GTA and Ottawa Reinforcement and WAMS) over the next three years.

78. Details of each of these items that contributed to the decision to proceed with a three year Capital Budget are set out below.

(i) Uncertainty with System Integrity and Reliability program outcomes

79. There are three main causes for the variability in the System Integrity and Reliability program cost forecasts. One is the fact that the scope and requirements of many of the System Integrity and Reliability programs will not be fully known until related studies are completed and there is some practical experience with the programs. The second is the fact that the Company anticipates more stringent Pipeline Integrity Management legislation, such as that contemplated in the United States,

but does not know when this will be implemented. The third is the continue evaluation on the Companies assessment of risk to the distribution system through the asset planning process. Future risk assessment will change the risks identified and the priorities of these risks.

80. Through the first two reviews of the Capital Budget, it had become clear that capital cost requirements for a five year period were hard to quantify with any specificity. Depending on the outcomes of System Integrity and Reliability studies, and the outcomes from early experience with new System Integrity and Reliability programs, the costs would vary. While there is uncertainty about the level of required costs even within a one year timeframe, the amount of the potential variance becomes unacceptably high when one forecasts five years into the future.

81. Examples of the variability in the System Integrity and Reliability cost forecasts are seen in the potential engineering outcomes of the MOP Verification Program, the In-Line Inspection Programs and the Process Hazard Assesment ("PHA") of the Gate and District Stations. The MOP and ILI Programs will identify segments of the distribution system that require replacing. However, the outputs of the inspection programs could identify a greater number of kilometres of pipeline or additional reinforcements than budgeted. The variability in length of pipeline replacement or predicting potential reinforcement projects has created a large swing in the Company's ability to firmly forecast capital expenditures. Similarly, the PHA's could yield a range of outcomes from minor component replacements to entire station replacements and/or relocations.

82. The uncertainty and variability in cost forecasts led the Company to determine that it could only create a dependable Capital Budget forecast for three future years, rather than five. At the same time, though, the Company also recognized that it may not be appropriate to include its uncertain (or potential) costs within the Capital

Budget being presented to support its Customized IR application. The solution that was reached was to identify that group of costs for each year, but not to include those costs, which are referred to as "variable costs" throughout this document, within the filed 2014 to 2016 Capital Budget. For example, Enbridge decided to implement a budget for the MOP program that would include the project costs for inspection and assessment (the "firm" costs), but not include any capital amounts for replacement of pipeline (the "variable" costs). The same approach has been taken for the ILI program.

83. The result is that Enbridge will be at risk for the "variable" costs associated with the System Integrity and Reliability studies and programs (as well as variable costs associated with other capital spending projects). The Company expects that at least some of the identified "variable" costs will materialize, so this is a real risk that will have to be accommodated by finding further efficiencies within the rest of the Company's operations. This was one of the items driving Enbridge to a three year Capital Budget (2014 to 2016). The Company has been very uncomfortable with shouldering the risk associated with these "variable" costs for more than three years. At this time, though, as described below in section G, Enbridge has determined that it is prepared to continue to take these risks for 2017 and 2018, by using the 2016 Capital Budget as the basis for forecasts of 2017 and 2018 capital spending. However, to address two of the most real risks which are outside of Enbridge's control, there will be variance account treatment for 2017 and 2018 capital costs related to relocations and to pipeline replacements required because of issues discovered through pipeline inspections (such as, but not limited to, the ILI and MOP programs).

84. Table 7, below, sets out the "firm" and "variable" budget amounts associated with System Integrity and Reliability studies and programs over the 2014 to 2016 term.

The total forecast of "firm" amounts is approximately $94 million, while the total forecast of "variable" amounts is approximately $116 Million. Stated differently, for the period of 2014 to 2016 the System Integrity and Reliability studies and programs have a potential "variable" spend that is approximately 108% of the budgeted "firm" amounts that are included within the Capital Budget.

Table 7
System Integrity and Reliability List of Firm and Variable Forecasts
(Thousands)

Project Name or Blanket Program	Firm 2014	Firm 2015	Firm 2016	Variable 2014	Variable 2015	Variable 2016
AMP Fitting Replacement	8,543	13,100	30,046	-	13,814	13,694
Bare Steel Drips (study & removal program)	255	-	-		2,335	2,289
Bare Steel Service Replacement						208
Casing Study & Program	510	-	-		531	520
EFV Program	500	604	733	2,254	1,432	1,405
Failure of Bonnet Bolts on Valves Study					212	
ILI for pipelines over 20% SMYS plus HCA	4,000	4,080	4,162	6,200	6,450	6,324
Isolated Steel Mains CP Program	82	-	-		85	83
Load Shed Zone	1,145	1,171	1,194		1,194	1,170
Low Pressure Delivery Meter Set Program	1,530	2,341	2,388	1,530	2,387	2,341
Meter boxes				179	186	182
Plastic Mains (incl Services) Study					11,143	10,925
Remote Control Valve Study & Installation	565	602	680		3,979	3,901
Targeted Compression Couplings Pressure Contair	1,622	2,040	2,061		1,061	1,041
Verification of MAOP	3,296	3,397	3,195	5,304	4,881	4,786
WingLock Valve Study & Replacement	204	-	-		849	832
Totals	22,251	27,335	44,459	15,467	50,539	49,701

85. Beyond the System Integrity and Reliability studies and programs, there are other items within Enbridge's 2014 to 2016 Capital Budget which have associated "variable" costs. Graph 1 shows the total amounts of additional capital costs that could arise between 2014 and 2016 but which have not been included in the Capital Budget (the "variable" costs). These "variable" costs total more than $160 million over three years, and increase each year from 2014 to 2016. Enbridge is accepting the risk that some of these costs will likely arise, and will have to be accommodated.

Witnesses: J. Sanders
P. Squires

	2014	2015	2016
Variable	25,142	63,031	75,937
Firm	468,627	461,631	458,054

(ii) Externally Initiated Projects

86. Another source of budget uncertainty relates to capital projects required to accommodate works being undertaken by Municipal and Provincial governments and organizations. Examples are large-scale transit projects and other infrastructure projects. These projects often require Enbridge to relocate or change distribution assets to accommodate construction activities.

87. Enbridge has found it challenging to forecast relocation requirements beyond the next few years, because details of transit and other infrastructure projects remain fluid. At the same time, though, the Company recognizes that the associated costs may be substantial. This has contributed to the difficulty of creating reliable five year Capital Budget forecasts.

Witnesses: J. Sanders
P. Squires

(iii) Large Complex Projects over the Next Three Years

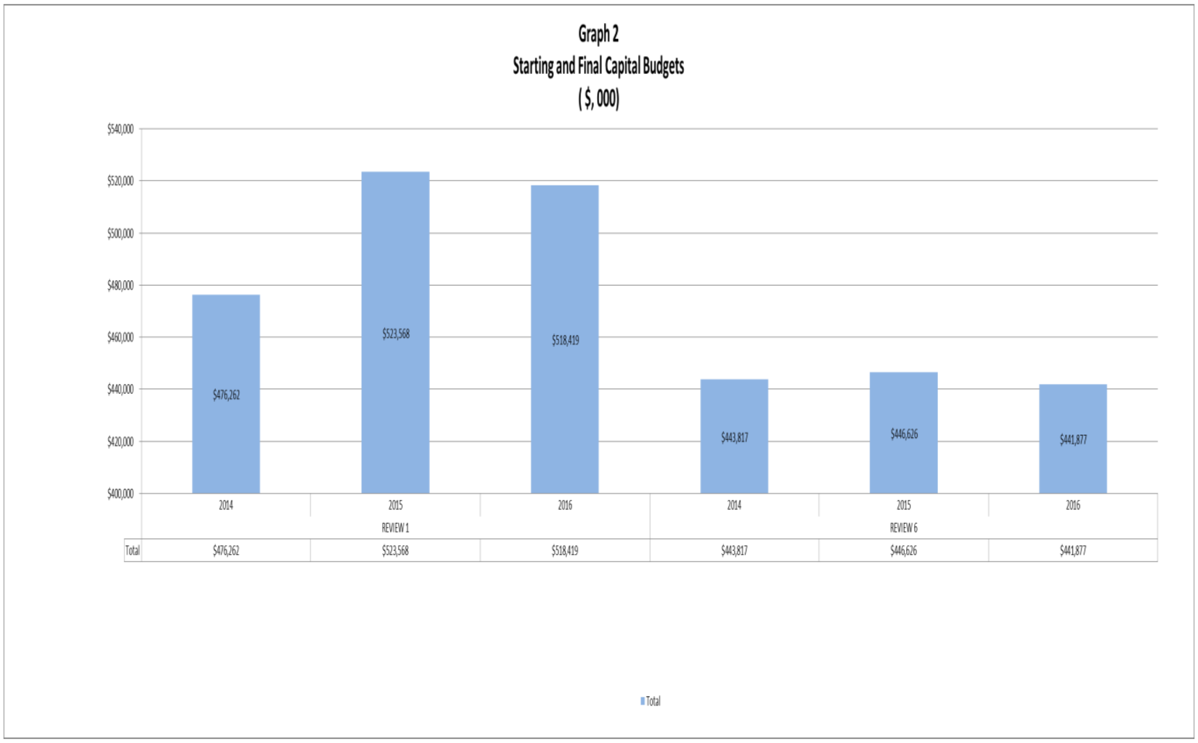
88. Enbridge determined that the use of a three year Capital Budget is consistent with the fact that the Company's capital spending requirements over the 2014 to 2016 period will be quite different from future years. The coming years are unusual because the majority of the Capital Budget increase arises from large complex capital projects that are contained within the 2014 to 2016 term (the GTA and Ottawa Reinforcements and WAMS project).

89. The Capital Budget process confirmed to the Company that the significant capital spending increase over the next three years is not a "business as usual" occurrence. Rather, this is an extraordinary period in Enbridge's history. Therefore, the Company concluded that a Capital Budget term of three years was the prudent approach to focus the utility on completing the large complex projects and to protect all parties from the consequences of presenting uncertain costs within the Company's filed budgets. At the same time, though, because the Company is taking the risk of uncertain "variable" capital costs, this approach will ensure focus on cost effectiveness.

The 2014 to 2016 Capital Budget

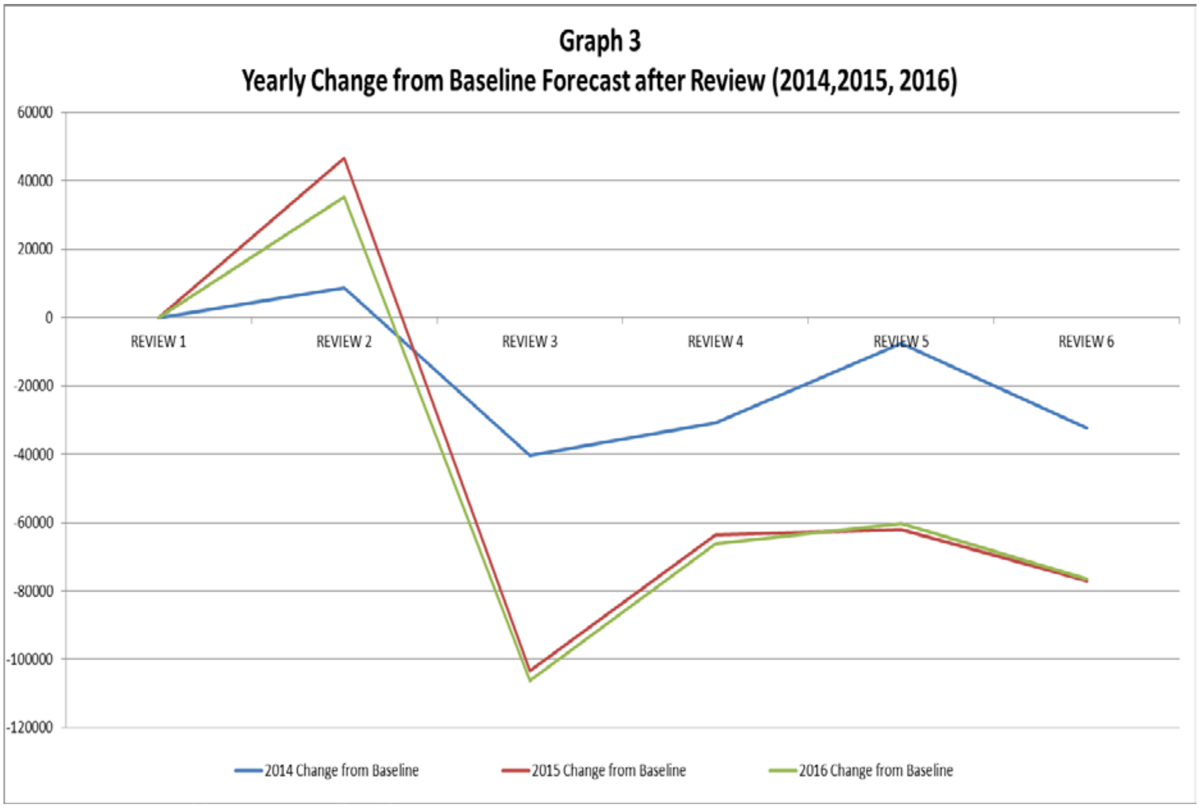
90. The 2014 to 2016 Capital Budget that resulted from the budget process is set out at Tables 1 and 2 above. From the start to end, the rigorous examination by the Capital Owners Committee and Executive Management of proposed capital budgets resulted in total reductions of approximately $185 Million for the three years or approximately 12.25% reduction from Review 1 to final approval. The annual reductions are approximately $32 Million, $76 Million and $77 Million for each year of 2014 to 2016. These annual amounts represent reductions of 6.8% in 2014, 14.7% in 2015 and 14.8% in the 2016.

91. The graph below shows the change from the opening capital forecast the final capital forecast as a result of the Capital Budget Refresh Process.



92. Given that the budgets related to the major projects were mostly unchanged from the outset of the budget review process, the changes that were made to the 2014 to 2016 Capital Budget mostly related to Core Capital amounts. The following graph sets out the Core Capital budget difference relative to the first budget after each review.

Witnesses: J. Sanders
P. Squires



93. Much of the change to the Core Capital amounts arose from the re-categorization of forecast costs as “variable”. As explained above, these costs are no longer included within the 2014 to 2016 Capital Budget; however, the Company expects that it will have to accommodate at least some of the costs. The following Table sets out the manner in which the Company’s categorization of “fixed” and “variable” costs evolved through the budget process.

Table 8

Yearly Change From Baseline After Each Review
($ 000)

REVIEW CYCLE	Sum of Firm 2014	Sum of Variable 2014	Sum of Firm 2015	Sum of Variable 2015	Sum of Firm 2016	Sum of Variable 2016
REVIEW 1	$ 476,262		$ 523,568		$ 518,419	
REVIEW 2	$ 485,010		$ 570,313		$ 553,820	
REVIEW 3	$ 435,739	$ 120,642	$ 420,039	$ 45,996	$ 411,591	$ 108,477
REVIEW 4	$ 445,509	$ 36,476	$ 459,964	$ 80,967	$ 452,251	$ 68,317
REVIEW 5	$ 468,627	$ 25,142	$ 461,631	$ 63,031	$ 458,054	$ 75,937
REVIEW 6	$ 443,817	$ 25,142	$ 446,626	$ 63,031	$ 441,877	$ 75,937

E. Incorporation of Productivity in the Capital Budget

94. Throughout the Capital Budget process, the Company worked to ensure that the Capital Budget amounts included cost savings due to efficiency and productivity. The following section outlines some examples of productivity initiatives incorporated in the proposed Capital Budgets for 2014 to 2016.

Departmental Labour Costs Productivity

95. As explained in the O&M evidence (for example, at Exhibit D1-3-1), the Company has resolved to maintain its overall FTE level (number of employees) flat through the 2014 to 2016 period. Executive management has determined that with a focus on efficiencies, the Core Capital programs (which are increasing to accommodate customer growth and System Integrity and Reliability programs) will be delivered within the existing FTE numbers.

96. One way of quantifying the productivity savings is to compare the departmental labour cost amounts within the 2014 to 2016 Capital Budget to the amounts that would be included using a 2% inflation rate from the 2013 levels.

Using that measure, there is a savings of approximately $14.98 million over the 2014 to 2016 term, as seen in the following table.

Table 9

Departmental Labour Cost Productivity
($ 000)

		2013 Budget	2014 Forecast	2015 Forecast	2016 Forecast	Total Productivity Savings
Management Approved Departmental Labour Cost Forecasts		$ 76.50	$ 74.84	$ 73.43	$ 75.55	
2013 Budgeted Departmental Labour Cost Increased by Inflation @ 2 %		$ 76.50	$ 78.03	$ 79.59	$ 81.18	
Productivity amount Forecast vs 2013 @2% Inflation		**$ -**	**$ 3.19**	**$ 6.16**	**$ 5.63**	**$ 14.98**

97. To the extent that additional FTEs are needed to accomplish work, (such that the assumption of no staff additions cannot be maintained), Enbridge will accommodate the associated costs within other parts of the Capital Budget. Enbridge is committed to finding efficiencies needed to make this work.

Productivity to Accommodate "Variable" Costs

98. As explained above, the Company has determined that there are large amounts of uncertain or "variable" costs that may arise over the 2014 to 2016 term, primarily through the delivery of the System Integrity and Reliability initiatives. Those "variable" costs, which total more than $160 million, are not included within the Capital Budget.

99. While the Company does not expect all of these "variable" costs to materialize, there is a strong possibility that at least some of the costs will arise during the 2014 to 2016 term. As these costs are not included within the Capital Budget, they will have to be accommodated elsewhere. The result will be a requirement to find further productivity and efficiency gains, to allow for all necessary work to be completed.

Witnesses: J. Sanders
P. Squires

F. Year over Year Variance Explanations

100. The 2014 to 2016 Capital Budget is set out at Tables 1 and 2 above. Part B of this Evidence described the main drivers of the overall budget during the 2014 to 2016 term. Set out below are high-level explanations of the year-to-year changes in the Capital Budget.

Major Changes: 2014 Capital Budget vs. 2013 Board Approved Budget

101. The 2014 Forecast is $682.3 million, which is $232.4 million or 51.6% over the 2013 Board Approved Budget of $449.9 million. Capital expenditure net increases in the 2014 Forecast are primarily driven by the requirements of three multi-year major initiatives; the GTA Reinforcement project, the Ottawa Reinforcement project and the Work and Asset Management System ("WAMS") project and an increase in System Improvement and Upgrades. The requirements of the three major projects contribute to $175.2 million of the variance, System Improvement and Upgrades accounts for $50.4 million of the variance and General and Other Plant needs increased by $8.2 million. The increase is partially offset by a $4.0 million decrease in the Customer Related (adding a new customer) requirements.

102. Table 10 below itemizes the major variances and the related evidence.

Table 10

2014 Forecast vs. 2013 Board Approved Budget Major Variance

2014 Test Year Budget vs 2013 Board Approved Budget ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	(4.0)	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	3.1	B2-7-1 Business Development
System Improvements and Upgrades	50.4	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	8.7	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(0.5)	B2-6-1 Underground Storage
"Core" Capital Requirements	**57.7**	
Work and Asset Management System (WAMS)	35.8	B2-8-2 Work and Asset Management
Leave to Construct Projects	138.9	B2-3-2 Major Reinforcements
Total Capital Expenditures	**232.4**	

Major Changes: 2015 Capital Budget vs. 2014 Capital Budget

103. The 2015 Forecast is $832.0 million, which is $149.7million or 21.9% over the 2014 Fiscal Year Budget of $682.3million. Capital expenditure net increases in the 2015 Forecast are primarily driven by the requirements of three multi-year major initiatives; the GTA Reinforcement project, the Ottawa Reinforcement project and the Work and Asset Management System (WAMS) project. The requirements of these three projects contribute to $146.9 million of the variance. The increase is partially offset by a $2.8 million decrease in the Core Capital requirements.

104. Table 11 below itemizes the major variances and the related evidence.

Witnesses: J. Sanders
P. Squires

Table 11

2015 Forecast vs. 2014 Forecast Major Variance

2015 Forecast vs 2014 Test Year Budget ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	7.8	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	0.2	
System Improvements and Upgrades	4.6	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	(3.6)	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(6.2)	B2-6-1 Underground Storage
"Core" Capital Requirements	**2.8**	
Work and Asset Management System (WAMS)	(10.6)	B2-8-2 Work and Asset Management
Leave to Construct Projects	157.5	B2-3-2 Major Reinforcements
Total Capital Expenditures	**149.7**	

Major Changes: 2016 Capital Budget vs. 2015 Capital Budget

105. The 2016 Forecast is $450.0 million, which is $382.0 million or 45.9% under the 2015 Forecast of $832.0 million. Capital expenditure decreases in the 2016 Forecast are primarily driven by the completion of two multi-year major initiatives; the GTA Reinforcement project and the Work and Asset Management System (WAMS) project. The completion of these two projects contributes to $377.3 million of the variance. The remaining $4.7 million decrease reflects fluctuations in the Core Capital requirements.

106. Table 12 below itemizes the major variances and the related evidence.

Table 12

2016 Forecast vs. 2015 Forecast Major Variance

2016 Forecast vs 2015 Forecast ($Millions)	Over/(under)	Related Capital Evidence by Business Area
Customer Related Distribution Plant	10.3	B2-2-1 Customer Growth and B2-10-1 Asset Plan
NGV Rental Equipment	0.1	
System Improvements and Upgrades	(5.6)	B2-3-1 Reinforcements, B2-4-1/5-1 Relocations/Integrity and B2-10-1 Asset Plan
General and Other Plant	(4.3)	B2-9-1 Facilities and General Plant, B2-8-1 Information Technology
Underground Storage Plant	(5.2)	B2-6-1 Underground Storage
"Core" Capital Requirements	**(4.7)**	
Work and Asset Management System (WAMS)	(17.6)	B2-8-2 Work and Asset Management
Leave to Construct Projects	(359.7)	B2-3-2 Major Reinforcements
Total Capital Expenditures	**(382.0)**	

G. 2017 and 2018 Capital Budget

107. As explained above, Enbridge is not able to forecast its 2017 and 2018 Capital Budget requirements on a line by line basis, in the same way as has been done for 2014 to 2016. However, the Company understands that some parties do not agree with the proposal to update capital costs for 2017 and 2018 midway through the IR term.

108. In response, Enbridge has updated its Customized IR proposal to allow for Allowed Revenue amounts to be set for all five years at this time. To accomplish this, Enbridge has used the 2016 Capital Budget to represent its 2017 and 2018 capital spending requirements within the Allowed Revenue amounts for 2017 and 2018. The one change that Enbridge has made to the 2016 Capital Budget is that, for purposes of 2017 and 2018, the $8 million forecast spending on WAMS has been removed, since that project will have been completed by the end of 2016. Therefore, the Capital Budget used for 2017 and 2018 is the same as set out in the "Forecast 2016" column within Tables 1 and 2 above, except that the $8.1 million

associated with WAMS is removed, leaving a forecast Capital Budget of $441.9 million for each of 2017 and 2018.

109. The Company believes the 2016 Capital Budget sets out a reasonable forecast of its capital spending requirements for 2017 and 2018. The 2016 Capital Budget sets out Enbridge's capital spending requirements within the context of continuing customer growth, and new system reliability and integrity requirements. While some of the line item requirements within the Capital Budget will change each year, Enbridge believes that the overall capital spending requirements for 2017 and 2018 will be in line with 2016.

110. Indeed, using the 2016 Capital Budget to represent Enbridge's capital spending requirements for 2017 and 2018 likely understates the Company's actual requirements for those years.

111. One way this can be seen in within the Asset Plan. In that document, Enbridge has forecast that its distribution plant capital spending requirements for 2017 and 2018 will be $23 million and $50 million higher as compared to 2016 (see Exhibit B2, Tab 10, Schedule 1, at page 91). The Asset Plan also indicates that Enbridge expects its customer growth for 2017 and 2018 to continue at the same rate as forecast for 2016 (around 40,000 new customers per year).

112. Another way that the 2017 and 2018 Capital Budgets can be seen to be understated is from the fact that there is no allowance for cost inflation in an approach which keeps the 2016 Capital Budget flat for the following two years.

113. As explained above, there are large amounts of uncertain, or "variable", capital costs that may arise within the 2014 to 2016 period associated with the System Integrity and Reliability studies and programs (as well as variable costs associated with other capital spending projects). Exposure to these variable amounts, which

are not included within the 2014 to 2016 Capital Budgets, will continue in 2017 and 2018.

114. While Enbridge is prepared to take most of the risk associated with these "variable" capital costs for 2017 and 2018, there are two areas (relocations, and replacement mains requirements identified through pipeline inspection activities (including the ILI and MOP programs)) where a different approach is proposed. For each of these areas, Enbridge proposes variance accounts for 2017 and 2018, through which the allowed revenue implications of spending that is significantly higher or lower than included within the budget would be recoverable from ratepayers. Details of the proposed variance accounts can be found at Exhibit D1, Tab 8, Schedule 6. It should be noted that the variance accounts are only operative if the actual Allowed Revenue consequences of required additional spending in either area are more than $1.5 above or below the forecast amount for that area (which is the same threshold as applies for Z Factors).

115. It is very difficult to forecast costs associated with relocations with any accuracy. This is described above, and within Exhibit B2, Tab 4, Schedule 1. That difficulty is exacerbated in years further into the future. Relocations requirements arise because of third party activities over which Enbridge has no control. Given the amount of development activity being undertaken within the Company's franchise areas, Enbridge observes that the amount and cost of relocation requirements is increasing even since the original filing in this proceeding. Therefore, the actual capital costs associated with relocations activity for 2017 and 2018 may be significantly higher than that forecast for 2016. It is for this reason that Enbridge proposes variance account treatment for 2017 and 2018 related to this category of activity.

116. One key “variable” cost that is not included within Enbridge’s capital cost forecasts for 2014 to 2016 is capital amounts related to pipeline replacement that is identified through the pipeline inspection programs. The Capital Budgets include the project costs for inspection and assessment of pipelines, but do not include the cost for replacements that result from the programs. The Miscellaneous Mains Replacement category of cost does not include any costs for pipeline replacement requirements identidifed through pipeline inspection programs. While Enbridge has indicated that it is prepared to take on the risk of the variable costs associated with these activities (capital amounts related to pipeline replacement) for 2014 to 2016, the Company believes that it is reasonable and appropriate to include variance account treatment for the revenue requirement implications of such costs for 2017 and 2018.

H. Conclusion

117. The balance of the B2 series of exhibits sets out the details of Enbridge’s 2014 to 2016 Capital Budget, organized by categories of capital spending (business areas). For each of the categories, the Company will provide Overview evidence, an explanation of the category’s capital budget, explanation of year-over-year budget variances, and individual project description documents for initiatives that have a capital budget over $2 Million during the three year term.

118. The following Table 13 sets out the direct costs for each of the major business areas detailed within the B2 series of Exhibits.

Table 13
Summary of Capital Expenditures by Business Area
($Millions)

		Col 1	Col 2	Col 3	Col 4
		Board Approved			
		Budget	Forecast	Forecast	Forecast
Exhibit Reference	Business Area	2013	2014	2015	2016
B2-2-1	Customer Growth	95.9	91.2	97.5	102.3
B2-3-1	Reinforcements	11.4	11.4	16.9	8.8
B2-3-2	Major Reinforcements	63.4	202.2	359.7	-
B2-4-1	Relocations	15.2	15.2	13.4	12.6
B2-5-1	Sytem Integrity and Reliability	84.7	132.3	135.1	141.1
B2-6-1	Storage	19.0	19.2	13.8	8.9
B2-7-1	Business Development	0.3	3.5	3.6	3.7
B2-8-1	Information Technology	28.0	29.3	27.2	27.5
B2-8-2	Work and Asset Management System (WAMS)	0.5	35.7	23.7	7.7
B2-9-1	Facilities and General Plant (includes Fleet)	15.5	23.6	22.0	17.3
	Sub total Capital by Business Area	333.9	563.6	712.9	329.9
B2-1-1	Departmental Labour Costs	76.6	74.8	73.4	75.6
B2-1-1	Capitalized Administrative and General	33.6	35.5	36.4	37.1
B2-1-1	Interest During Construction	5.4	8.4	9.3	7.4
B2-1-1	Total Capital Expenditures	449.5	682.3	832.0	450.0

119. This Capital Budget Overview and Budget Process exhibit has explained the Company's approach, reasoning and decisions that led to the 2014 to 2016 Capital Budget. The budgeting process has ensured that Enbridge's Capital Budget reflects the level of spending necessary to meet the growth, safety and operational requirements of the business. The inclusion of productivity savings within the Capital Budget reflects Enbridge's commitment to demonstrate cost effective operation during an extraordinary period of expenditure.

120. As explained at Exhibit A2, Tab 3, Schedule 1, the Capital Budgets for 2014 to 2016 are used as an input into the Allowed Revenue amounts for each year of the Customized IR term, with the adjusted 2016 Capital Budget (exclusive of WAMs spending) used as the relevant input for 2017 and 2018. This updated approach enables Allowed Revenue to be set for each of the five years of the Customized IR term.

Witnesses: J. Sanders
P. Squires

Customer Growth Capital Budget Forecast: 2014 to 2018

Overview

1. Customer Growth capital includes costs associated with the construction and installation of mains, services, meters, regulator stations and the associated equipment required to facilitate the connection of new gas customers within the Enbridge Gas Distribution franchise area. These new customers include attachments from residential subdivision, residential replacement (conversions of existing homes), commercial buildings, apartment buildings (both individually metered units (ensuite) and single meters per building) and industrial end uses. Customer growth capital is based on and evaluated using the principles previously established through EBO 188.

Customer Additions

2. The customer additions forecast for the 2014 to 2016 period, in addition to the 2013 budget, is outlined in Table 1. The development and explanation of the customer forecast numbers are explained in Exhibit B3, Tab 2, Schedule 1.

Table 1

Customer Growth 2013 to 2016[1]

2013B	2014	2015	2016
38,579	36,647	38,489	39,645

3. As noted in Table 1, the customer additions forecasts are expected to be in excess of 36,000 annually and trending upwards towards the end of the forecast period.

[1] Customer growth forecasts were updated in Q1 2013 and would be different from customer growth forecasts presented in other proceedings which relied on earlier forecasts.

Witnesses: F. Ahmad
D. Lapp

This trend is consistent with the housing starts forecast outlined in Table 2 below. These trends are also projected forward beyond 2016 as outlined in the Asset Plan, Exhibit B2, Tab 10, Schedule 1.

Table 2

Housing Starts Forecast

	2013	2014	2015	2016
Ont Housing Starts	64,387	61,757	72,822	74,345
EGD Housing Starts	41,712	39,913	47,135	48,241

4. The customer additions by sector reflect the continued residential growth over the forecast period in both the residential subdivision and residential replacement markets, accounting for over 93% of the customer additions growth. The commercial sector including traditional apartment buildings constitute over 6% of customer additions growth and industrial make the balance.

5. Steady residential growth in the new construction sector is reflected in the strong additions in areas covering the Greater Toronto Area ("GTA") which includes the Regions of Peel and York. Growth in the City of Toronto is steady in the residential sector, with higher proportions of commercial and apartment growth than the other less urban areas, owing to the densification efforts currently underway in support of the Places to Grow Act.

Customer Growth Capital

6. The Customer Growth Capital Budget is presented on Table 3 for the 2014 to 2016 period, in addition to 2013 budget figures. As described above, the capital costs for Customer growth include construction and installation costs for mains, services,

meters, regulator stations and associated equipment attributed to the addition of new customers.

Table 3

Customer Growth Capital 2014 to 2016

Table 3: Customer Growth Capital 2014 to 2016				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Direct Costs ($000)	95,939	91,156	97,495	102,340
Customer Additions (units)	38,579	36,647	38,489	39,645
Direct Cost per Customer ($)	2,487	2,487	2,533	2,581

7. The customer growth capital budget is compiled based on the following approach. The projected customer additions for the budget year are segregated by market segment (residential, commercial and industrial) and geographical area (Toronto, Barrie, Ottawa). The Connections and Construction department determines if the cost drivers for a typical customer addition, in a given market segment and geographical area, still apply for the upcoming budget year. Cost drivers include the mix between improved (hard surface restorations) and unimproved (soft surface restoration) installations for services and mains; changes in the mix of pipe diameters and material (plastic and steel); and the ratio of rural and urban installations; the length of main per attachment, the average service length; and finally the season of installation (winter construction has a cost premium). If there are no changes required, the historical unit costs are used to calculate the total capital requirement for the upcoming budget year. The historical costs are based on approximately 5 years of customer connection cost data.

8. There are instances where changes in the customer connection costs can be required. These include potential contractor cost, material cost and changes to the mix of cost drivers noted above. Finally, costs can be adjusted for any new or revised standards for main and service installations as described below.

9. For the 2014 to 2016 period, the overall cost per customer add extrapolated from the 2013 Budget, is applied to 2014 and escalated for 2015 and 2016.

10. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%.

11. Material costs for mains include all the various sizes of pipe (steel and polyethylene), protective coatings, valves, fittings such as elbows, tees and tie-in fittings, required to distribute natural gas through the rights of way and roadways, enabling supply to customers' premises.

12. Material costs for services and meters include similar materials to mains, such as pipe, coatings, valves and fittings (usually in smaller sizes than mains); but also include the individual customers' pressure control regulator and meter to bring natural gas from the mains to the buildings and facilities of the end use customer.

13. Material costs for regulator stations include the various sizes of pipe, valves, fittings, pressure control regulators, relief valves and filters associated with the pressure regulating facilities within the distribution system that control pressure, and provide over pressure protection between the different pressure systems.

14. Labour costs for the above include both internal and contractor resources and equipment required for the excavation, pipe joining (welding or polyethylene fusion) pipe laying or fabrication, backfilling, testing and commissioning and final clean-up and restoration for mains, services, meters and regulating stations.

15. The material and labour components will be influenced by the customer mix between market sectors such as residential versus commercial or industrial, where residential customers require smaller sized distribution infrastructure versus commercial or industrial customers.

16. Construction labour costs are influenced significantly by ground cover and land use. For example the labour costs associated with new subdivision or Greenfield construction are substantially lower than built up urban construction. Greenfield developments are in open fields or land where there is minimal traffic and congestion, generally requiring little or no clean-up or restoration, while urban construction requires traffic control, working in congested urban areas with extensive pavement and sidewalk excavation and restoration.

17. Virtually all of the labour for customer growth capital is provided by pipeline contractors. Labour rates for these contractors are dictated by trade union agreements, including welders and fitters, operators, labourers and teamsters.

18. The overhead costs for customer growth capital are described more broadly with the overall capitalized overheads as part of the Capital Budget Overview at Exhibit B2, Tab 1, Schedule 1. Some of the more significant capitalized overhead items included in customer growth capital include the planning, design, scheduling, inspection, note keeping and records creation associated with the construction and installation of these assets.

Witnesses: F. Ahmad
D. Lapp

Productivity and Efficiencies

19. The continued evaluation and implementation of new construction efficiencies, materials and technology are essential to offset the cost pressures associated with contractor labour rate increases, mentioned above, as well as for ensuring worker, public and process safety and regulatory compliance.

20. Practices including the requirement to acquire sewer later locates using specialized equipment and methods prior to construction has increased the time required to install customer growth projects. This practice is a proactive step to ensure public safety and ensure that the new mains and services are not breaching sewer laterals which is a threat that has been addressed by the construction industry in recent years. The costs associated with the additional time required for this practice must be offset with innovative construction techniques and technologies.

21. The need to locate and excavate in the vicinity of existing live gas plant is a necessary requirement when installing customer growth infrastructure, particularly in built up urban areas within the Enbridge franchise area. The Technical Standards and Safety Authority (“TSSA”), in conjunction with the Electrical Safety Authority (“ESA”) have issued “Guidelines for Excavation in the Vicinity of Utility Lines” (“Excavation Guidelines”), where the requirements are outlined, including the requirement for locates and “hand excavation” within 0.3m of natural gas pipelines, as opposed to mechanical excavation methods. An approved alternate to hand digging is the use of hydro-vac to expose the buried natural gas pipelines, primarily to protect the worker from damaging the infrastructure. To ensure compliance with the Excavation Guidelines, hydro-vac is the preferred method of construction for Enbridge contractors. Additional costs for third party hydro-vac contractors and the scheduling and utilization of this equipment, requires scheduling and productivity

enabling processes to ensure the added costs are managed within the customer capital requirements.

22. Residential developers, particularly around the GTA, are continuing to get an early start on construction in recent years, commencing their land development activities in the winter months. This is requiring Enbridge to increasingly construct their new construction infrastructure during the winter months as well, necessitating the payment of a “winter premium” to contractors. This winter premium is paid to compensate contractors for the additional effort required to construct in the winter, including snow removal, excavation through frost, etc. The incremental costs for winter construction must also be offset with new construction methods and technologies. An example of this in practice is the pre-installation of road crossing pipe in new subdivisions prior to winter, eliminating the requirement to bore or excavate under new roads that are being built in these areas.

23. The increased municipal and conservation authority requirements to the protection of the natural environment, including trees, wetlands, environmentally sensitive areas, has necessitated the increased use of trenchless technology or boring to lessen the impact on these features. The additional costs required to install pipelines and facilities in these areas necessitates alternate construction methods as well as planning and design standards changes avoid or mitigate the impacts of construction on these features to avoid these additional costs.

24. Construction techniques, technologies and practices are continuously tested, evaluated and implemented at Enbridge to improve efficiency, safety and quality. Joint utility trench construction (“JUT”) is one such method that is used extensively in subdivision or Greenfield projects. JUT involves the excavation of a single trench that has a customized profile and is used for the installation of gas, electric and

telecommunications infrastructure. The customized profile provides for compliant separation and depth of cover for the various individual utilities. The JUT contractors will excavate the trench, install the various pipes and cables to their respective specifications, and backfill the excavation. This practice is both efficient and improves construction safety. The installation of the various utilities within a single excavation provides labour savings, and also eliminates the need to excavate around hydro and other utilities at different times, minimizing the potential for third party excavation damages. Enbridge utilizes JUT extensively in most operating areas for subdivision mains and services.

2014 to 2016 Capital Requirements – Reinforcements

Introduction

1. Reinforcement projects are the installation of new or modification of existing gas distribution plant to maintain minimum required system pressures. Adequate system pressures are required to maintain the capacity to meet customer demand. These projects are driven by Customer Growth and System Reliability considerations. This pre-filed evidence supports the requested total expenditure of $49.9 million for pipeline reinforcements over 2014 to 2016.

2. As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up Enbridge's franchise. The objective at Enbridge for network design is that the system must meet anticipated peak hourly demand. The peak hourly demand is the combination of the base load demand and the temperature-dependent demand. All load additions to the system are modeled based on this design temperature as shown in Table 1.

Table 1: Regional Peak Daily Design Temperature

Temperature Region	Peak Temperature[1]	Degree Day
Peterborough & Lindsay	-28 °C	46
Georgian Bay & Barrie	-26 °C	44
Ottawa Area	-29 °C	47
Greater Toronto Area	-23 °C	41
Niagara Area	-21 °C	39

Note: 1. This peak temperature is the average temperature on the peak day.

Reinforcement Planning Process

3. On an annual basis the System Analysis and Design group completes 4 major functions as part of planning for reinforcements. These are Load Gathering, Simulation, Annual Forecast and long range Planning, each of which is discussed below. This process allows Enbridge to build and validate the piping system models based on actual field conditions. Enbridge uses SynerGEE Gas, a pipeline simulation software produced by GL Noble Denton, to simulate the pressures and flows in the gas distribution network. Forecasted growth, both short and long term, are incorporated into these models to predict system performance. The two outcomes of this process are small localized reinforcements that are required for the upcoming heating season, and larger projects that are to be incorporated into the Company's Asset Plan.

Load Gathering

4. The Load Gathering process extracts actual billed customer consumption data for all accounts and matches this with locally recorded temperatures for each customer. This data gathering process provides Enbridge with a reliable, repeatable and predictable process that generates individual customer consumption. Based upon the temperature inputs and the predicted customer consumption, a load for each customer is assigned to selected points within the system models. Specific large volume customers are reviewed on an annual basis and loads are assigned based on actual consumption and contractual parameters.

Simulation

5. The Simulation function is performed after the heating season by utilizing the system models with the customer consumption from the Load Gathering process. This combination of inputs provides the basis for the pipeline pressure and flow analysis. The resultant pressure and flow information is then compared to actual field chart or recorder readings taken during seasonally cold temperatures throughout the gas distribution system. The loads and pressure inputs of the final system models are adjusted to simulate field conditions. This verified model then becomes the piping system of record that can then be used for all subsequent piping system analysis.

Annual Forecast

6. Using the verified model described above, additional customer loads that are forecasted for the upcoming heating season are applied. Overall system pressures and station flows are assessed to ensure that all system minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring and in some cases small localized reinforcements will be required.

Planning

7. Enbridge engages in long range planning that considers a minimum of 10 years of customer growth to ensure the adequacy of system performance over the longer term.

8. The forecasted future customer growth is obtained from a number of different sources. The primary source of information is the growth forecast by operating

region provided by the Customer Portfolio & Policy group as presented in Exhibit B3, Tab 2, Schedule 1 (Growth Customer Additions and Average Cost Per Customer) of the pre-filed evidence. Information obtained from development correspondence with government agencies, municipalities, consultants, and developers, is used to allocate customer growth and loads. The information regarding additions is used to better predict various local growth trends and planned developments.

9. Reinforcement solutions are considered if minimum system pressures cannot be maintained with forecasted loads applied. Each of the reinforcement segments identified is evaluated on a case by case basis considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, damage history, constructability, cost, environmental impacts and future expansion or development potential.

10. The results of the long range planning process is an input to the capital budget and planning of construction activities to minimize disruptions and proactively maintain the gas piping systems in an efficient and reliable manner.

11. These larger reinforcement projects are itemized and incorporated into the Asset Plan.

<u>Reinforcement Requirements</u>

12. The profile for capital requirements is summarized in Table 2.

13. The year to year variances are the result of the lumpy nature of reinforcement projects, such as the York Region Reinforcement. These projects, identified by the planning process above, are each estimated to determine the capital requirement.

Table 2: Capital Requirement Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Alliston Reinforcement	-	-	1,040[1]	2,111
Harmony Conlin Reinforcement	-	-	-	3,714
York Region Reinforcement Phase 1	-	510	10,404	-
Identified Projects Less than $2M	6,995	8,078	2,653	-
Other Localized Small Reinforcements	4,405	2,805	2,861	2,918
Reinforcement Direct Resource Cost		4,662	4,882	3,240
Total	11,400	16,055	21,840	11,984

Note: 1. Contingent on customer timing.

Alliston Reinforcement

1. Project Description

The Alliston extra high pressure (XHP) system supplies several communities with gas, including the areas of Alliston, Cookstown, Nottawasaga, Everett, Beeton and Tottenham. Alliston and the surrounding area are continuing to experience economic and population growth. The peak hour load at design conditions for the 2012/2013 winter was approximately 31,000 m^3/hr and is forecasted to reach approximately 52,000 m^3/hr in the winter of 2019/2020.

The Alliston Reinforcement is comprised of the following 4 phases:

Table 1: Alliston Reinforcement

Phase	Year	Description	Required Capital
1	Completed 2012	9 km of NPS 8 XHP ST main	N/A
2	2013	1.8 km of NPS 8 XHP ST main	$1.04 million
3	2016	2.8 km of NPS 8 XHP ST main	$2.11 million
4	2019	3 km of NPS 6 XHP ST main	N/A

This project will increase system capacity to ensure that supply continues to meet demand for the area. Phases 2 and 3 of this project will be completed between 2014 and 2016 with the installation of approximately 1.8 km and 2.8 km of NPS 8 XHP steel pipeline operating at a maximum of 500 psi. Phase I of this project was approved in a Leave to Construct proceeding, EB-2011-0323, which identified Phases 2, 3 and 4.

The proposed routes for Phases 2 and 3 have been outlined in Figure 1.

The proposed pipeline for Phase 2 will connect with Phase 1 at 10th Sideroad and Highway 89 and run 1.8 km to 14th Line and 10th Sideroad. The chosen route for the pipeline is expected to be entirely within the road allowance for 10th Sideroad. The timing of this phase will coincide with a planned development in the area of 10th Sideroad and 14th Line. The cost of this phase is included in the customer growth main extension portfolio.

The proposed pipeline for Phase 3 will connect Phase 2 at 14th Line and 10th Sideroad and run along 10th Sideroad and 14th Line to the existing NPS 6 XHP pipeline Industrial Parkway. A new XHP-XHP station (500 psi drop to 400 psi) is required to tie into the existing NPS 6 (operating at a maximum pressure of 400psi) at Industrial Parkway and 14th Line. The chosen route for the pipeline is entirely within the expected road allowances and will require one river crossing.

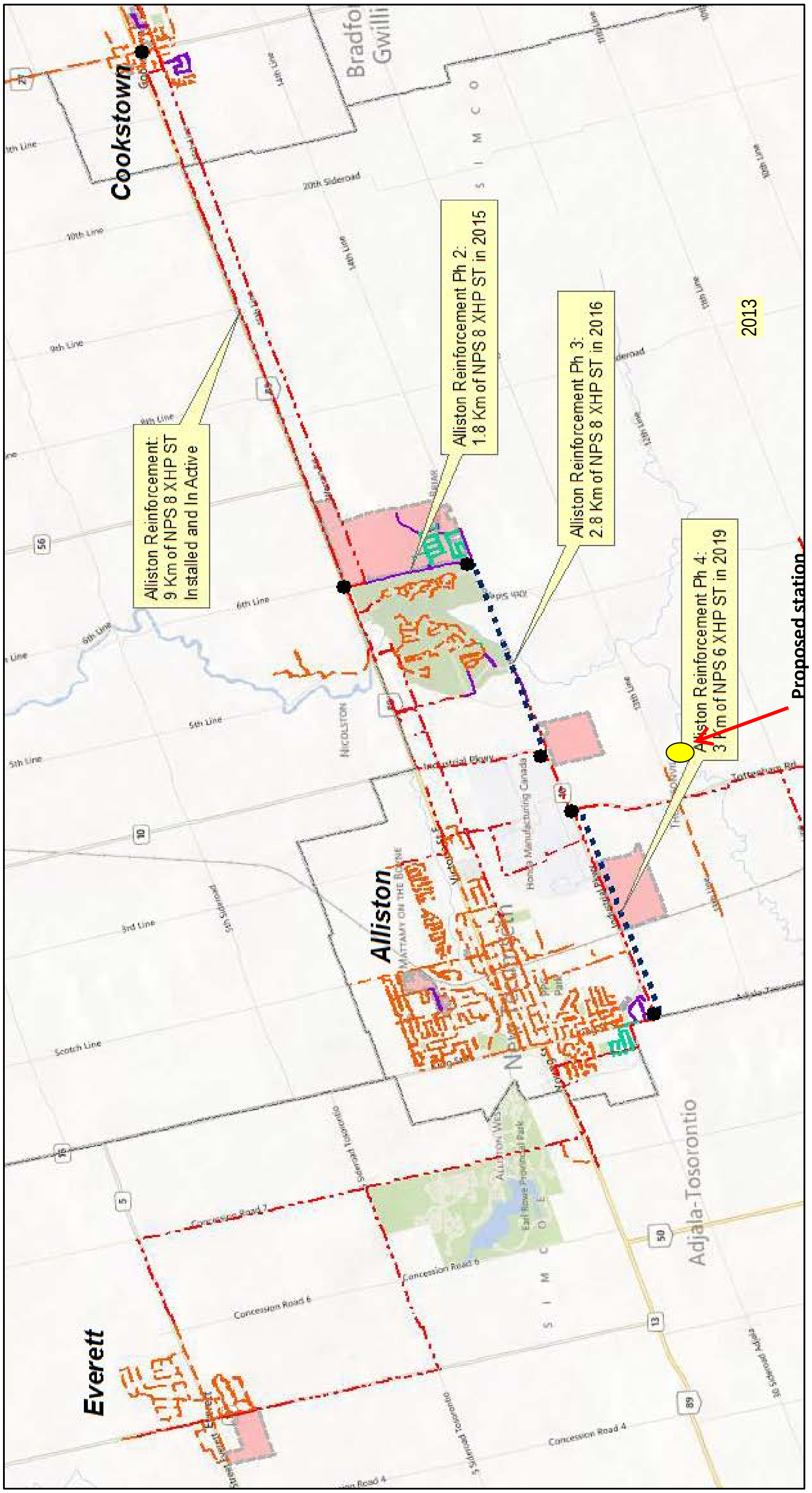


Figure 1: Alliston Reinforcement Route Selection

2. Project Justification

The proposed pipeline addresses the need to increase the capacity of the Alliston distribution system to meet the increased demand over the next 10 years due to economic and population growth.

The installation of Phase 1 increased system capacity to approximately 43,500 m^3/hr. The forecasted demand on the system for the 2016/2017 winter is approximately 44,000 m^3/hr. Without the completion of Phase 2 and Phase 3, the system pressure will drop below the minimum required system pressure in the winter of 2016/2017.

In EB-2011-0323 the Profitability Index for the completion of Phases 1 thru 4 was 1.37.

3. Reinforcement Options

The following options were examined for the Alliston reinforcement where an NPS 8 reinforcing pipeline was selected as the solution because it provides system flexibility, provides a reliable supply of gas beyond the 10 year forecast, and is economically feasible. In addition to a new reinforcing pipeline, Enbridge considered looping the system, pressure elevation and supply from the Shelburne system.

New Reinforcing Pipeline

Enbridge considered 3 new reinforcing pipeline options. Network analysis was completed using ten year forecasted loads with NPS 12, NPS 8 and NPS 6 gas main options. The NPS 6 option will meet the demand of 2018/2019 winter but will not provide the demand for 2019/2020 winter. Additional reinforcement of the system would be necessary in year 2019. Given the system configuration, the NPS 8 and NPS 12 provide similar system performance.

Based on cost and the potential pipeline capacities, an NPS 8 reinforcing pipeline was selected as the preferred alternative because it provides a reliable supply of gas for the 10 year forecast and beyond, and is a lower cost than the NPS 12 alternative.

Looping the Existing Pipeline

Looping of the existing pipeline on Mackenzie Pioneer Road, from Hwy 89 and 10th Sideroad to Addison Road (Simcoe Road) and Mackenzie Pioneer Road, was considered. This would require 3.3 km of NPS 8 XHP but would not capture the additional customers directly supplied by the recommended alternative.

Pressure Elevation

The Alliston pipeline was originally installed in 1986. At that time, this pipeline was installed to feed the Town of Alliston and was operating at 400 psi. In 2010, the pipeline was pressure elevated to 500 psi and drops to 400 psi at Leach & Mackenzie Pioneer XHP station to feed the Alliston-Everett-Beeton system.

Reinforcements

Pressure Elevating the Alliston-Everett-Beeton system was considered as one of the reinforcement options. This requires elevating the MOP of approximately 9.4 km of NPS 6, 49 km of NPS 4 and 7.5 km of NPS 2 XHP ST main from 400 psi to 500 psi. These pipelines were installed in 1961. This option also involves: rebuilding one Gate Station (Bond Head Gate), installing one new XHP-XHP Station, completing 16 IP District station inlet pressure elevations, and potential modification to gas services of 500 customers. This option was not preferred due to the significant station and service work required and the inability to meet the longer term gas supply requirements.

Service from the Shelburne Network

The option of connecting the Shelburne system to the Alliston system was considered as a reinforcement option. This option would require construction of approximately 21 km of NPS 4 XHP ST predominately along Hwy 89. Due to the small pipe size and pressure of the existing Shelburne system, servicing from this network would not provide a reinforcement supply to the Alliston system.

4. Required Capital

The estimated direct capital of Phase 2 of the Allison reinforcement is $1.04 million. Phase 3 is estimated to cost $2.11 million. These estimates cover all costs related to material, construction and labour, land acquisitions and contingencies. A station capacity increase is required as part of this overall reinforcement. The costs associated with the increase in capacity at Cookstown Gate Station are shown in Exhibit B2, Tab 5, Schedule 4, Attachment 1.

5. Benefits and Costs Savings

The reinforcement of the Alliston system will allow Enbridge over the next 10 years and further to accommodate the economic and population growth being observed and predicted.

HARMONY CONLIN REINFORCEMENT

1. Project Description

The Harmony Conlin NPS 12 extra high pressure (XHP) pipeline services the Pickering and Oshawa area, and total system capacity is forecasted to be exceeded by the winter of 2016/2017. The Harmony Conlin Reinforcement will replace 2 km of NPS 12 steel (ST) XHP pipe with 2 km of NPS 16 ST XHP pipe in 2016, as described in Figure 1. An NPS 16 pipeline will add incremental capacity to the system while allowing the existing NPS 12 pipeline to be abandoned. The estimated direct capital for this reinforcement is $3.7 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

The new pipeline will run from the outlet of Oshawa Gate Station to the intersection of Conlin Road and Wilson Road. The existing NPS 12 main operates at 400 psi and the new main will also operate at 400 psi and will provide the required additional capacity to the network.

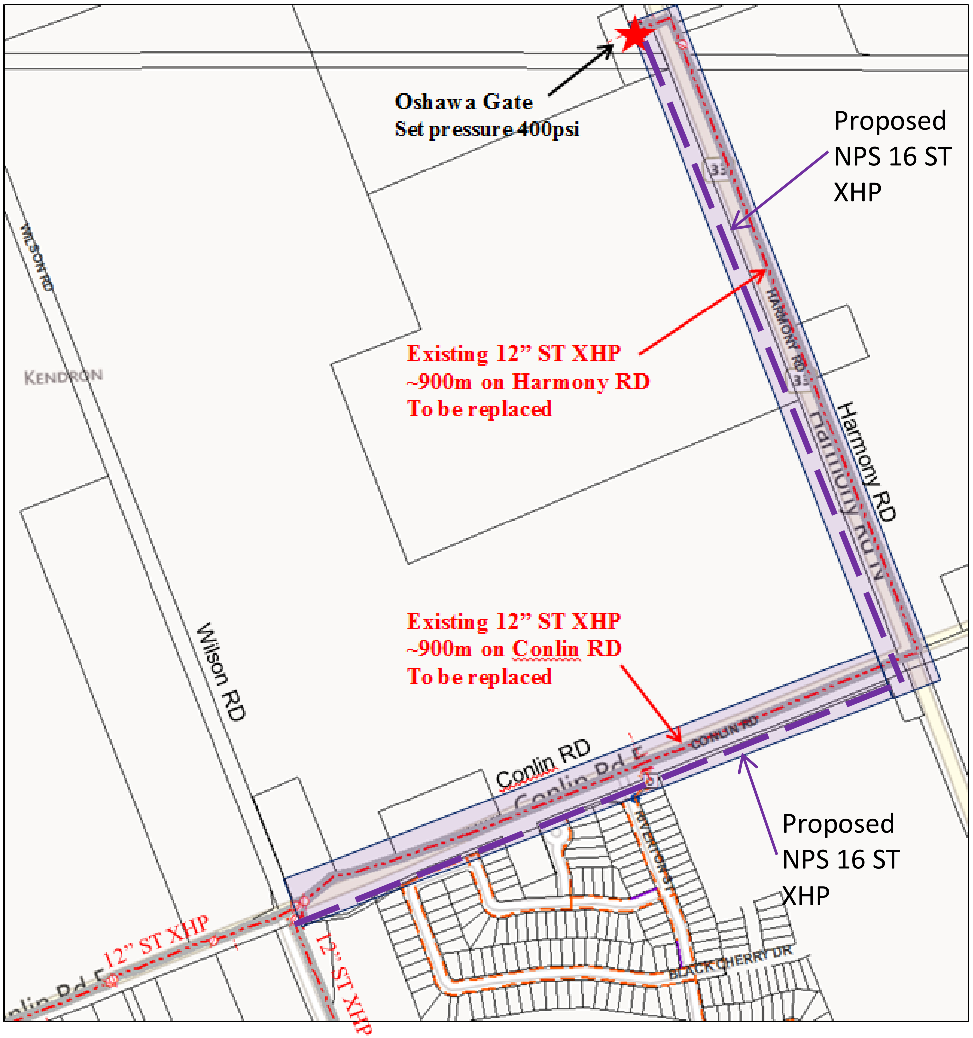


Figure 1: Harmony Conlin Reinforcement Route Selection

2. Project Justification

The proposed pipeline will accommodate growth over the next 10 years in Durham Region and will service approved subdivisions in the Pickering-Oshawa area. As noted above, the existing pipeline operates at 400 psi and has a total capacity of approximately 32,000m^3/hr and is expected to approach system minimum pressures by the winter of 2016/2017. The reinforcement will operate within the required pressure range and will increase system capacity by 19,000 m^3/hr and allow the system to expand to meet increasing demand.

With the expected growth and known integrity concerns on the existing pipeline, replacement with a larger pipe diameter to increase system capacity is the recommended solution (as described below).

3. Historical Reliability/Performance

The NPS 12 Oshawa pipeline is approximately 4 km long and consists of Grade 207 and Grade 290 pipes. There are sections of this pipeline that are of integrity concern; these sections are Grade 207 and located approximately 1.7 km downstream of Oshawa Gate Station and 250 m on Wilson Rd.

The entire length of the pipeline was inspected using Inline Inspection (ILI) with magnetic flux logging (MFL) and caliper tools in September 2011. ILI results indicated deformation anomalies and corrosion anomalies. During mitigation the first Stress Corrosion Cracking (SCC) colony in the Enbridge system was discovered, as well as large corrosion clusters at the bottom of the line at several locations.

The vintage of the Grade 207 sections of pipe in this line are also prone to Electric Resistance Welding (ERW) long seam anomalies. Considering the extent of the corroded areas of the pipe, the additional defects identified through ILI, and the pipe vintage it is recommended to replace the entire length of the Grade 207 sections in this pipeline.

4. Reinforcement Options

To increase system capacity in Oshawa-Pickering for forecasted growth, 3 options were examined:

Recommended Approach:

Replace the existing NPS 12 ST XHP main with NPS 16 ST XHP main

The recommended approach will accommodate 10 years of growth, eliminates a pipeline with known integrity issues from the distribution system, and is the most cost effective solution. The estimated cost of this option is $3.7 million.

Alternative Option (a):

Loop the existing NPS 12 ST XHP main with another NPS 12 ST XHP main

This option is not acceptable even though it will provide the additional capacity required, as it does not address the integrity issues that exist on the existing NPS 12 line and will require system modifications. The cost of 2 km of NPS 12 pipe is estimated at $2.5 million, with additional costs required to modify Oshawa Gate Station to accommodate multiple outlet pressures. Numerous integrity indications have also been identified on this segment of pipeline. Should the line remain in service, a pigging cost of approximately $500,000 every 7 years will be incurred as well as the costs to remediate any identified indications. Based on the estimated costs and unknown costs associated with future integrity remediation, replacing this pipeline with an NPS 16 is recommended.

Alternative Option (b):

Pressure elevate the existing XHP main from Pickering Gate to Taunton Rd and Salem Rd from 400 psi to 485 psi, Install a pressure limiting Station at Taunton Rd and Salem Rd, and Install 4000 m of NPS 12 ST on Westney Rd from Taunton Rd to south of Kingston Rd

This option requires more pipe than the recommended approach and it does not address the integrity issues that exist on the NPS 12 line. For these reasons it was not pursued any further.

5. Required Capital

The estimated direct capital for the Harmony Conlin Reinforcement is $3.7 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

6. Benefits and Costs Savings

Completion of this project will enable Enbridge to continue to meet growth demands for at least the next 10 years in Durham region, while eliminating a pipeline with known integrity concerns.

Appendix C: York Region Reinforcement

C1. Project Description

The existing XHP pipeline, known as the Woodbine NPS 12 XHP, that supplies York Region is not expected to meet the capacity requirements for the region over the next 10 years based on growth forecasts. There is approximately 10,000 m^3/hr of capacity remaining in the system until it reaches its minimum system pressure currently expected in 2015. With growth, additional load in the system is forecasted to increase by approximately 40,000m^3/hr by 2021.

The York Region Reinforcement will provide the additional capacity needed for York Region and also enable system flexibility with the ability to transfer load from multiple gate stations. The project consists of constructing 6.5 km of NPS 16 ST XHP, including the connection to existing NPS 12 pipeline on Bathurst Street. Bathurst Gate Station capital work related to this reinforcement is budgeted in Exhibit B2, Tab 5, Schedule 4, Attachment 1.

The proposed route is outlined in Figure 2. The proposed pipeline is approximately 6.5 km and will originate from Bathurst Gate Station, run north on Bathurst Street, and terminate at Bathurst Street and Bloomington Road.

The estimated direct capital requirement for the York Region Reinforcement is $10.9 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

C2. Project Justification

This reinforcement will supply Richmond Hill, Aurora, Newmarket, King Twp, Bradford, East Gwillimbury and Georgina. The proposed pipeline will address the residential and commercial growth that has been forecasted for York Region between 2013 and 2018. York Region's projected population growth is estimated at 390,000 people by 2021 which creates an expected increase load demand of approximately 40,000 m^3/hr for the area. By the heating season of 2015/2016, load growth is expected to consume the remaining 10,000 m^3/hr of system capacity. Reinforcing the existing distribution network will ensure sufficient gas supply for the region. Its completion will meet forecasted capacity requirements and improve security of supply for the area.

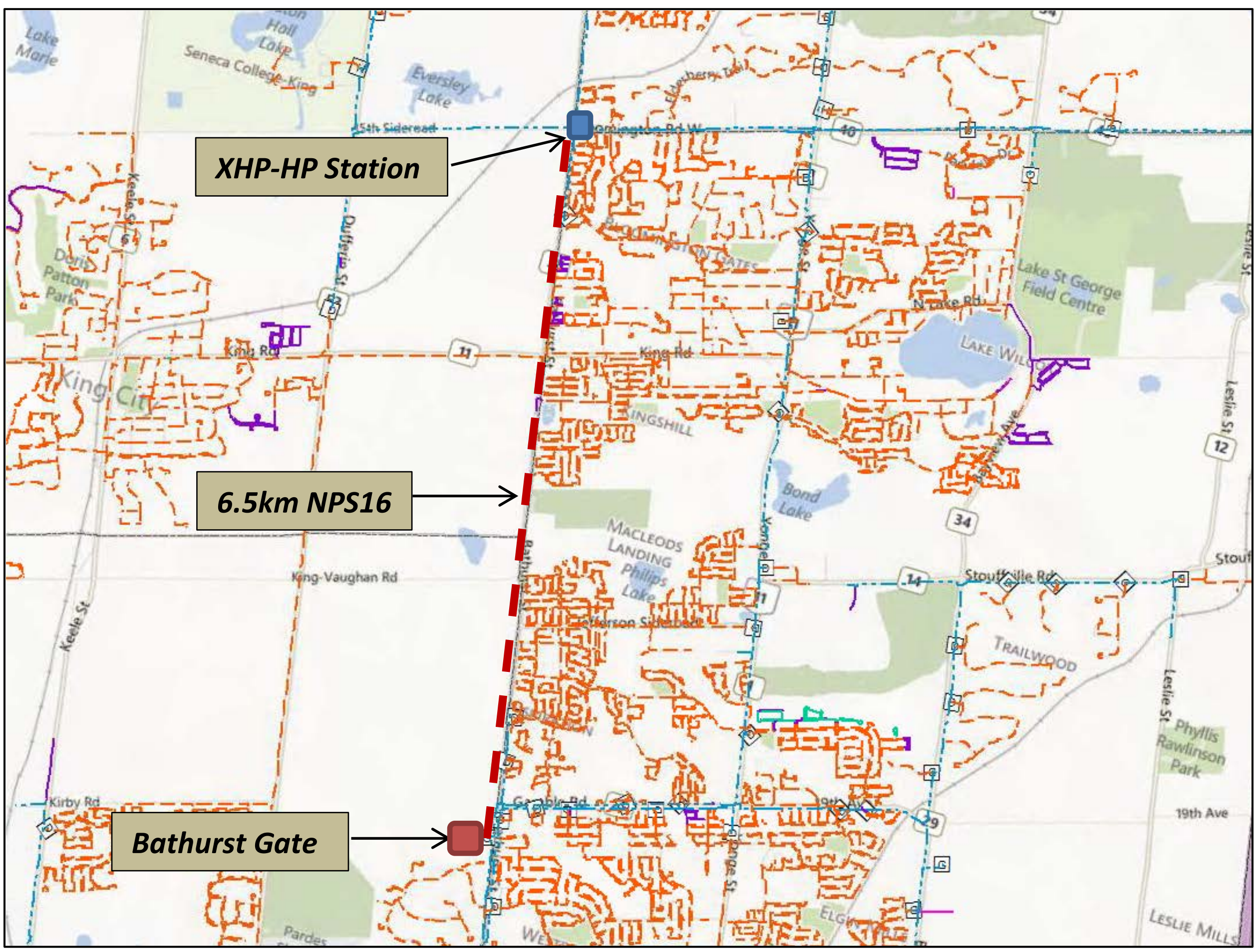


Figure 2: York Region Reinforcement Route Selection

C3. Reinforcement Options

When comparing route selections, line location constructability, length of pipe, system capacity, and system security were considered.

To increase system capacity in York Region, 3 options were examined:

Recommended Approach

Rebuild Bathurst Gate Station; install 6.5 km of NPS 16 from Bathurst Gate to Bloomington Road; install an XHP to HP station at Bloomington Road

The route along Bathurst Street will introduce a new XHP supply into Enbridge's Distribution system. This option provides the least material cost, constructability risk, and service disruption. It will also improve system reliability and security.

Alternative Option (a)

Rebuild Victoria Square Gate Station with new outlet, install 7.4 km of NPS 16, looping existing NPS 12, originate from Victoria Square Gate and terminate at Bloomington Road and Woodbine Avenue

The Victoria Square Gate option was not selected because the line location constructability was lower than the Bathurst option due to the possibility of sharing the line location with an existing NPS 12 main. The amount of pipe required was also greater than the Bathurst route, and the pipe route would not allow as much flexibility in supply as Bathurst. This option did not improve security of supply, where the area is still reliant on a single gate station to the area (Victoria Square Gate Station).

Alternative Option (b)

Rebuild Schomberg Gate Station, install 10 km of NPS 16 looping existing NPS 16 (YEC line)

Tying into the existing NPS 16 pipeline that supplies York Energy Centre was not selected because a high system minimum delivery pressure of 480psi is required to supply YEC. The amount of pipe required was also greater than the Bathurst route, and the commitment to maintain delivery pressures at YEC would require looping the existing system, which would require additional pipe.

C4. Required Capital

The estimated direct capital of the York Region Reinforcement is $10.9 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

C5. Benefits and Costs Savings

The York Region reinforcement will enable Enbridge to continue to meet the gas demand over the next 5 years in the region due to economic and population growth. The reinforcement will also increase the reliability of supply as there will be greater flexibility to move gas throughout the distribution system.

YORK REGION REINFORCEMENT

1. Project Description

The existing XHP pipeline, known as the Woodbine NPS 12 XHP, that supplies York Region is not expected to meet the capacity requirements for the region over the next 10 years based on growth forecasts. There is approximately 10,000 m^3/hr of capacity remaining in the system until it reaches its minimum system pressure currently expected in 2015. With growth, additional load in the system is forecasted to increase by approximately 40,000m^3/hr by 2021.

The York Region Reinforcement will provide the additional capacity needed for York Region and also enable system flexibility with the ability to transfer load from multiple gate stations. The project consists of constructing 6.5 km of NPS 16 ST XHP, including the connection to existing NPS 12 pipeline on Bathurst Street. Bathurst Gate Station capital work related to this reinforcement is budgeted in Exhibit B2, Tab 5, Schedule 4, Attachment 1.

The proposed route is outlined in Figure 3. The proposed pipeline is approximately 6.5 km and will originate from Bathurst Gate Station, run north on Bathurst Street, and terminate at Bathurst Street and Bloomington Road.

The estimated direct capital requirement for the York Region Reinforcement is $10.9 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

2. Project Justification

This reinforcement will supply Richmond Hill, Aurora, Newmarket, King Twp, Bradford, East Gwillimbury and Georgina. The proposed pipeline will address the residential and commercial growth that has been forecasted for York Region between 2013 and 2018. York Region's projected population growth is estimated at 390,000 people by 2021 which creates an expected increase load demand of approximately 40,000 m^3/hr for the area. By the heating season of 2015/2016, load growth is expected to consume the remaining 10,000 m^3/hr of system capacity. Reinforcing the existing distribution network will ensure sufficient gas supply for the region. Its completion will meet forecasted capacity requirements and improve security of supply for the area.

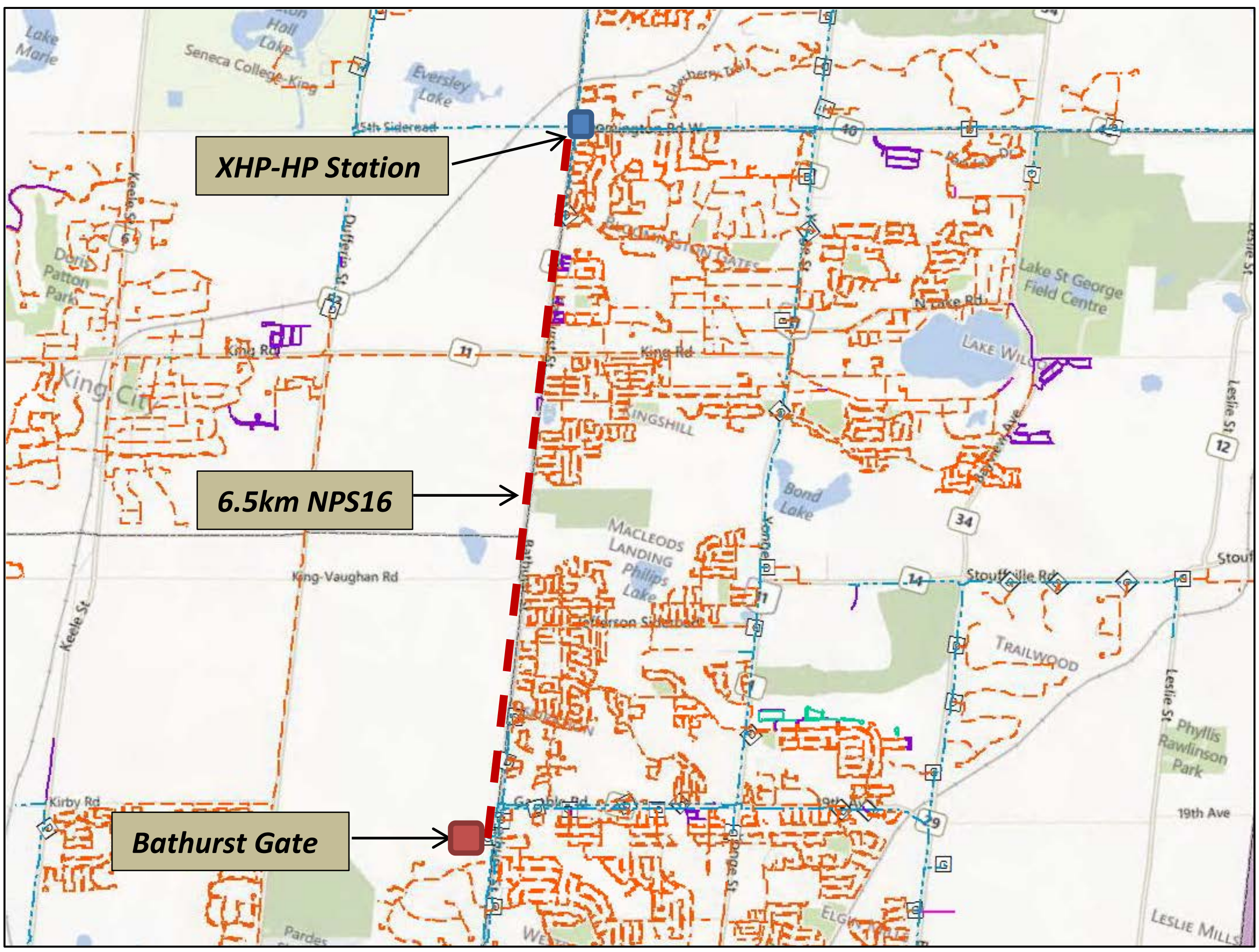


Figure 1: York Region Reinforcement Route Selection

3. Reinforcement Options

When comparing route selections, line location constructability, length of pipe, system capacity, and system security were considered.

To increase system capacity in York Region, 3 options were examined:

Recommended Approach

Rebuild Bathurst Gate Station; install 6.5 km of NPS 16 from Bathurst Gate to Bloomington Road; install an XHP to HP station at Bloomington Road

The route along Bathurst Street will introduce a new XHP supply into Enbridge's Distribution system. This option provides the least material cost, constructability risk, and service disruption. It will also improve system reliability and security.

Alternative Option (a)

Rebuild Victoria Square Gate Station with new outlet, install 7.4 km of NPS 16, looping existing NPS 12, originate from Victoria Square Gate and terminate at Bloomington Road and Woodbine Avenue

The Victoria Square Gate option was not selected because the line location constructability was lower than the Bathurst option due to the possibility of sharing the line location with an existing NPS 12 main. The amount of pipe required was also greater than the Bathurst route, and the pipe route would not allow as much flexibility in supply as Bathurst. This option did not improve security of supply, where the area is still reliant on a single gate station to the area (Victoria Square Gate Station).

Alternative Option (b)

Rebuild Schomberg Gate Station, install 10 km of NPS 16 looping existing NPS 16 (YEC line)

Tying into the existing NPS 16 pipeline that supplies York Energy Centre was not selected because a high system minimum delivery pressure of 480psi is required to supply YEC. The amount of pipe required was also greater than the Bathurst route, and the commitment to maintain delivery pressures at YEC would require looping the existing system, which would require additional pipe.

4. Required Capital

The estimated direct capital of the York Region Reinforcement is $10.9 million. This covers all costs related to material, construction and labour, land acquisitions and contingencies.

5. Benefits and Costs Savings

The York Region reinforcement will enable Enbridge to continue to meet the gas demand over the next 5 years in the region due to economic and population growth. The reinforcement will also increase the reliability of supply as there will be greater flexibility to move gas throughout the distribution system.

MAJOR REINFORCEMENTS 2014 - 2016

Overview

1. Over 2014 to 2016, there are two major reinforcement projects. These are the Ottawa Reinforcement Project and the GTA Reinforcement Project. Both projects have been previously filed with the Ontario Energy Board ("Board") for a Leave to Construct ("LTC"). The Ottawa projects was filed under EB-2012-0099 and subsequently approved by Board Decision and Order, dated November 29, 2012. The GTA project was filed under EB-2012-0451 with the proceeding current before Board.

2. Further information is provided for the Ottawa project in this evidence under Exhibit B2, Tab 3, Schedule 2, Attachment 1 and for the GTA project under Exhibit B2, Tab 3, Schedule 2, Attachment 2.

3. Table 1 provides the forecasted capital requirements for both projects.

Table 1: Major Reinforcement Projects ($000)				
Description	2013	2014	2015	2016
Ottawa Reinforcement Project	46,000	5,100	_	_
GTA Reinforcement Project	14,903	197,085	359,660	_
Total	60,903	202,185	359,660	_

Witnesses: C. Fernandes
D. Lapp
J. Sanders

OTTAWA REINFORCEMENT PROJECT

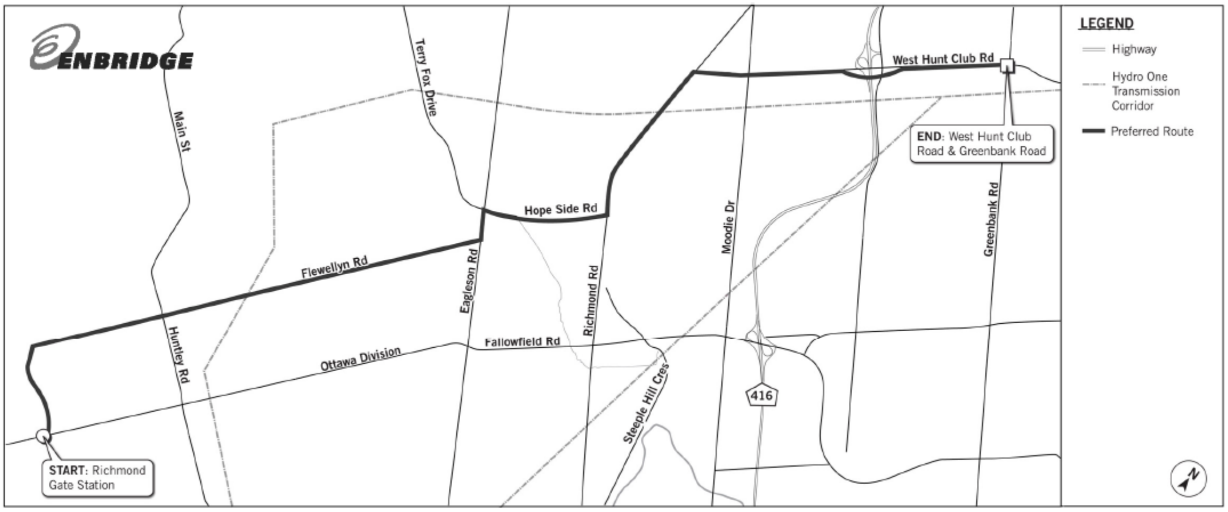
Project Overview

1. This project was filed as an application for a Leave to Construct order under sections 90 and 97 of the Ontario Energy Board Act (1988), under docket EB-2012-0099, and was subsequently approved by OEB Decision and Order, dated November 29, 2012.

2. The proposed facilities for the Ottawa Reinforcement Project include 19 km NPS 24 XHP steel pipeline and ancillary facilities including a rebuild of Richmond Gate Station to accommodate the increased gas volumes being offset from Ottawa Gate Station. The NPS 24 pipeline will originate at the Richmond Gate Station and end at a tie-in point at the intersection of Hunt Club Road and Greenbank Road, tying into the existing NPS 12 XHP pipeline on Greenbank. Two additional tie-in points will be located at Shea Road and Eagleson Road. A map of the proposed facilities is shown below in Figure 1 below.

3. The proposed rebuild of Richmond Gate Station will consist of upgrading the inlet piping from TCPL, the regulator and meter runs as well as the heating system. Further, the relocation of existing odorant tank and reconfiguration of the station piping is required to accommodate the proposed NPS-24 pipeline.

Figure 1



Purpose, Need and Timing for the Project

4. The greater Ottawa area continues to experience strong customer growth. The area has seen growth of over 50,000 customers over the past 7 years and is expected to grow by more than 77,000 customers over the next 10 years.

5. The proposed facilities address the need identified by Enbridge Gas Distribution Inc. ("Enbridge") to increase capacity of the Ottawa area distribution system to meet forecast loads as well as provide additional security of supply and operational flexibility.

6. Two key design parameters include; maintaining minimum system pressures ("MSP") at key locations in the distribution network, and managing flows through the supplying gate stations – Ottawa Gate and Richmond Gate.

7. Maintaining minimum system pressures at key control points in the Ottawa distribution system is required to supply the downstream networks, including the Rideau Heights Station which cannot be supplied for the winter of 2013-2014 without the installation of the Ottawa Reinforcement.
8. The current capacity at Ottawa Gate inlet from TransCanada Pipelines ("TCPL") is insufficient to handle the current peak flow requirements without mitigative pressure and flow measures in the operation of the distribution system for the winter of 2012-2013.

9. In order to meet the commitment to serve the Ottawa area, reinforcement will be required by winter 2013-2014. Construction of the proposed NPS 24 XHP pipeline is scheduled to commence March 2013, with a proposed in-service date for the project of January 2014.

Ottawa Reinforcement Project Costs

10. The project costs for the Ottawa Reinforcement Project are outlined in Tables 1 and Table 2 below. The total approved project costs by category are outlined in Table 1, while the estimated expenditures by year are on Table 2.

Table 1

Ottawa Reinforcement Project Costs

Description	**Cost ($'000)**
Materials	8,678
Labour	30,775
External	3,364
Land	677
Overheads	2,175
Contingency	5,567
Total Project Costs	51,235

Table 2

Otttawa Reinforcement Project Costs by Year (approx.)

2011	2012	2013	2014
$79.0	$982.0	$46,000	$5,100

11. The costs for the Ottawa Reinforcement Project were approved through the Leave to Construct order EB-2012-0099, issued on November 29, 2012. The capital costs for the project were also approved through the Interim Rate Order EB-2011-0354 as outlined in the Settlement Agreement, dated November 29, 2012.

Benefits

12. The completion of the Ottawa Reinforcement Project will provide the increased capacity required to meet the forecast growth in the greater Ottawa area, starting the winter of 2013-2014. This is accomplished by ensuring adequate pressures are maintained in the distribution system, and the security of supply is maintained due to throughput, take away and capacity limitations at the delivery points to the Ottawa system from TCPL.

THE GTA PROJECT
CAPITAL EXPENDITURES
2014 – 2016 BUDGET

Facilities description

1. In EB-2012-0451 Enbridge is proposing two segments of natural gas pipelines and associated facilities, referred to as "Segment A" and "Segment B". The pipelines and associated facilities are described below with references to Figures 1 and 2 attached. Figure 1 is a map overview of the proposed facilities in its entirety. Due to the larger map scale in Figure 1, Figure 2 is an expanded overview of the Parkway By-Pass and NPS 36 tie-in described below.

2. Segment A consists of:
   - A new NPS 36 pipeline, approximately 20.9 km in length, that will originate at the proposed interconnection with TransCanada's Mainline transmission system, the "Bram West Interconnect" (Reference 1 in Figure 1, also expanded in Figure 2) and terminate at the existing Enbridge Albion Road Station (Reference 2 in Figure 1);
   - An expansion to the existing Albion Road Station (Reference 3 in Figure 1); and,
   - A tie-in to the existing XHP system via:
     - Parkway West Gate Station and approximately 315 m of NPS 36 pipe to tie into the existing Enbridge NPS 36 Parkway North pipeline (Reference 4 in Figure 1, also expanded in Figure 2); and,
     - An upgrade to the current valve manifold at the existing Parkway By-Pass to include pressure regulation between the existing NPS 36 Parkway North pipeline and the existing NPS 36 Mississauga Southern Link ("MSL") pipeline that currently operate at different pressures (Reference 5 in Figure 1, also expanded in Figure 2).
     - The above components create a 'sister site' (Parkway West), and provide a back-up to the existing Parkway gate station, allowing for complete shutdown of Parkway without loss of supply to the system.

3. Segment B consists of:
   - A modification of the existing Keele/CNR Station (Reference 6 in Figure 1);
   - 23 km of NPS 36 XHP pipe that consists of a west-east portion and a north-south portion:
     - The west-east portion will originate from the existing Keele/CNR Station to the existing NPS 30 Don Valley pipeline (Reference 7a on Figure 1); and,
     - The north-south portion south to the tie-in point with the existing NPS 36 pipeline north of Sheppard Avenue East (Reference 7b on Figure 1);
   - A new pressure regulation facility, known as "Buttonville Station", located in the Parkway Belt corridor east of Woodbine Avenue, will tie the new NPS 36 pipeline into the existing NPS 30 Don Valley pipeline (Reference 8 on Figure 1); and
   - An expansion to the existing pressure regulation facility at Jonesville Station, located just north of Eglington Avenue East near Jonesville Crescent that will support the existing NPS 36 pipeline feed to the existing NPS 30 Don Valley pipeline running south from the Jonesville Station (Reference 9 on Figure 1) to Station B.
   - Collectively, the expansion of Jonesville and the new Buttonville station will allow for regulation between the NPS 30 Don Valley line and the new line (including the NPS 36 section built as part of PEC project), allowing for the operating pressure of the NPS Don Valley line to be lowered.

Business Rationale

4. The GTA Project will:

   i. Meet customer growth requirements over the period from 2015 to 2025 by reinforcing the XHP distribution network;

   ii. Reduce operational risks and enhance safety and reliability by:

      1. Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines & providing additional supply sources for major XHP lines in the GTA Project Influence Area;

      2. Providing the ability to lower pressures on key supply lines (NPS 30 Don Valley line and the NPS 26 line);

   iii. Provide entry point diversity by reducing the dependence upon Parkway Station which currently provides more than 50% of the supply to the GTA and which does not have alternate means of supply; and

   iv. Improve supply chain diversity, reduce upstream supply risks and reduce gas supply costs over the period 2015 to 2025.

Economics

The economic feasibility, utilizing standard methods used and approved by the OEB, is positive. This means, that over the life of the proposed facilities, the project should have a positive impact on rate payers.

The feasibility of the GTA Project is driven by;

a) the ability to supply incremental volumes forecast over the next 10 years in the Toronto core;

b) gas supply savings resulting from the replacement of long haul transport on the TCPL mainline with short haul transport from Niagara and/or Dawn;

c) Shared usage of Segment A with TransCanada, with Enbridge providing a transport service for TransCanada over this pipeline segment

The feasibility model does not attribute a monetary value to the substantial distribution and supply reliability benefits of the project; these are qualitatively described in evidence.

Capital Expenditures

The base case scenario for Segment A of the Project is a NPS 36 pipeline, with capacity shared 50%/50% with TCPL. Other potential, but less likely, outcomes include a NPS 42 pipeline shared 60% TCPL and 40% Enbridge or a NPS 36 pipeline with Enbridge owning 100% of the capacity. An explanation and comparison of these outcomes, and their associated feasibility, is included at [REFERENCE] of the EB-2012-0451 evidence.

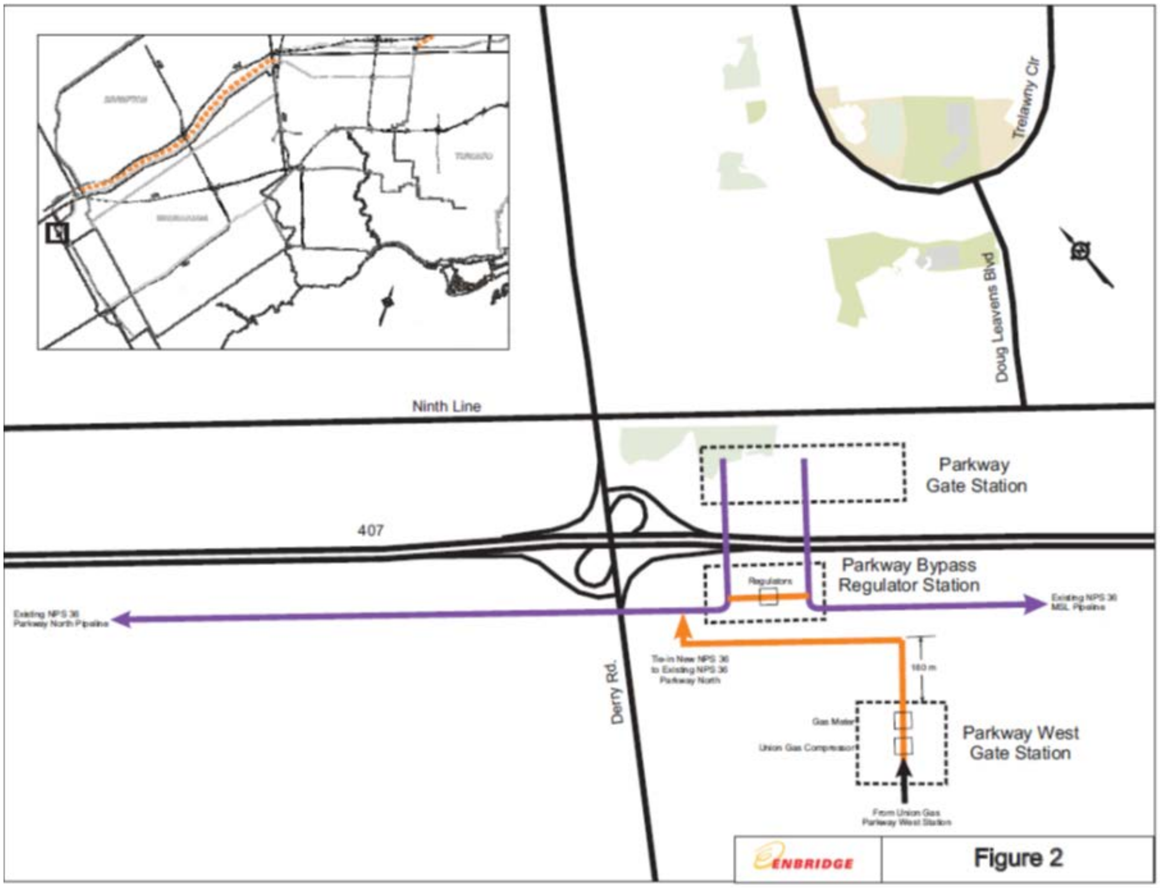
The 2014-2016 Capex for the GTA Project (escalated and including IDC), based on the "NPS 36 Shared" scenario for Segment A, is as follows.

	2013 Estimate	2014 Budget	2015 Budget
GTA Project $(000)	14,903	197,085	359,660

FIGURE 1


Segment A
Segment B
NPS 36 Parkway North
NPS 26 line
NPS 30 Don Valley line
NPS 36 MSL line
1
2
3
4
5
6
7a
7b
8
9
VAUGHAN
RICHMONDHILL
MARKHAM
BRAMPTON
TORONTO
MISSISSAUGA
Proposed Pipeline
GTA Project
Existing Pipelines
ENBRIDGE
GTA PROJECT
Figure 1

FIGURE 2


Trelawny Cir
Doug Leavens Blvd
Ninth Line
Parkway
Gate Station
407
Parkway Bypass
Regulator Station
Regulators
Existing NPS 36
Parkway North Pipeline
Existing NPS 36
MSL Pipeline
Tie-in New NPS 36
to Existing NPS 36
Parkway North
160 m
Derry Rd.
Gas Meter
Union Gas Compressor
Parkway West
Gate Station
From Union Gas
Parkway West Station
ENBRIDGE
Figure 2

2014 to 2016 CAPITAL REQUIREMENTS - RELOCATIONS

Introduction

1. The purpose of this evidence is to support the 2014 to 2016 capital requirement of $41.2 million for relocation work net of any contribution over the forecast period. Relocation is the capital required to relocate existing plant – size for size, such as mains, services, meters, and regulators, as a result of direct conflicts with third parties. Gas distribution assets generally need to be relocated for reasons such as road and sewer work and other municipal or third party construction projects.

Distribution Asset Management: Planning and Design

2. For relocations, the Planning and Design group within Distribution Asset Management is responsible for identifying situations where a third party's proposed work is in direct conflict with our existing gas assets. The Planning and Design Group ensures that such conflicts are resolved within the framework of the various agreements, applicable legislation and to ensure the continued safe and reliable delivery of natural gas to our end users.

Relocations

3. Enbridge representatives attend the regular meetings of the various municipal Utility Coordinating Committees ("UCC") and their sub-committees dealing with capital works. Through these meetings, various stakeholders discuss projects which may impact others and can lead to the need to relocate existing plant. Utilities and the municipality will circulate proposals for work at which time the potential to be in conflict (insufficient separation) with existing infrastructure is identified. Through various means, the work is either redesigned to avoid the conflict or identified as a relocation project.

4. Relocation requirements primarily arise from road realignments and expansions, sewer and water work, bridge rehabilitation, grade separations or other developments that are initiated by a municipality or other third party.

5. When reviewing third party work for potential conflict, the first approach is to avoid or mitigate costs, including the abandonment of the plant in direct conflict, through redesign of the proposed plans. Discussions are held in order to mitigate or avoid relocating existing natural gas plant wherever feasible.

6. Often, due to multiple agencies within a limited roadway or the size and scope of a particular project, relocating existing gas assets is the only solution.

7. Enbridge is obligated under our existing franchise agreements and under legislation such as the *Public Service Works on Highways Act* to relocate its main under various levels of cost sharing when conflicts cannot be avoided. In many cases, based on the agreements in place, Enbridge is able to recover a portion or all of the relocation costs. Where recovery is not available, the entire cost of the work will be at Enbridge's cost.

8. Municipal capital works lists may have several years of potential projects identified. Actual detailed planning of these projects cannot begin until the year and month the municipal budgets are approved at council, which is typically in the spring of the same year as construction.

9. Once the municipal capital works programs are set, detailed designs are completed in order to begin planning and estimating costs associated with any relocation.

10. Therefore, when forecasting future years' relocations, Enbridge begins with the historical level of relocation activity and then adds projects or programs identified as incremental to that historical level.

11. On top of the historic actual costs, where known, Enbridge considers externalities that may impact the relocation requirements. In the past, such externalities have been a result of increased infrastructure spending from the various levels of government.

12. Enbridge experienced such an externality in 2013, large scale transit, which resulted in a considerable step change in relocation activity. A number of significant incremental activities, which are already underway or announced, are driving forecast relocation costs above historical levels. The change from our historic budget to the current levels is directly attributable to the recent activity in infrastructure spending in large scale transit projects throughout the franchise. The transit projects are forecasted to continue for many years to come.

Capital Requirements – Relocations

13. In the years from 2010 to 2012, annual costs were between $6 and $9.5 million across all regions within the franchise. Projects or programs identified as incremental to that normal activity level are then added.

14. In 2013, the current estimate projection for relocations will be approximately $15 million. Transit projects account for approximately $5 million of this cost. The amount forecasted in 2013 is representative of the activity level during the forecast period.

15. For 2014 to 2016, the base historic amounts and known projects, at or near design stage, account for approximately $10 million. The incremental costs for transportation projects range between $3 million and $6 million.

16. The costs associated with transportation infrastructure will form part of the ongoing relocation dollars going forward as transportation infrastructure spending and the associated relocations will continue throughout the forecast period.

17. A summary of the 2013-2016 forecast capital requirements for relocations is presented in Table 1.

Table 1: Capital Requirement Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Relocations	9,795	9,236	9,386	9,603
York Regional Rapid Transit Corporation	5,441	6,000	4,000	3,000
Total	15,236	15,236	13,386	12,603

Notes:

1) 2013 forecast spend and new infrastructure transportation spend create new base year.

Witnesses: L. Chiotti
I. Taylor

York Regional Rapid Transit Corporation Expansion Relocation Program

1. Project Description

The York Regional Rapid Transit Corporation Expansion Relocation Program encompasses the net costs (rebillable) for natural gas pipeline relocations associated with transit expansion projects in York Region. The proposed route for the new Bus Rapidways will travel within the right-of-way along Highway 7, Yonge St and Davis Dr. Due to traffic considerations, utility congestion, and construction scheduling, the gas relocation work will be completed in phases between 2013 and 2018.

The York Region Rapid Transit Corporation's expansion plans call for construction projects that have been estimated at $4 billion. The

2. Project Timing

The Bus Rapidways are dedicated bus routes in the centre of the roadway. This will result in gas relocations to account for station building, road widening and utility relocations. The roadways affected by this construction work have major arterial gas mains that feed stations and smaller grid mains along the proposed route. Currently, most phases of the Rapidway are still in design and all conflicts have yet to be identified. It is anticipated that much of the gas infrastructure along these routes will eventually have to be relocated to allow for construction to proceed.

3. Alternatives

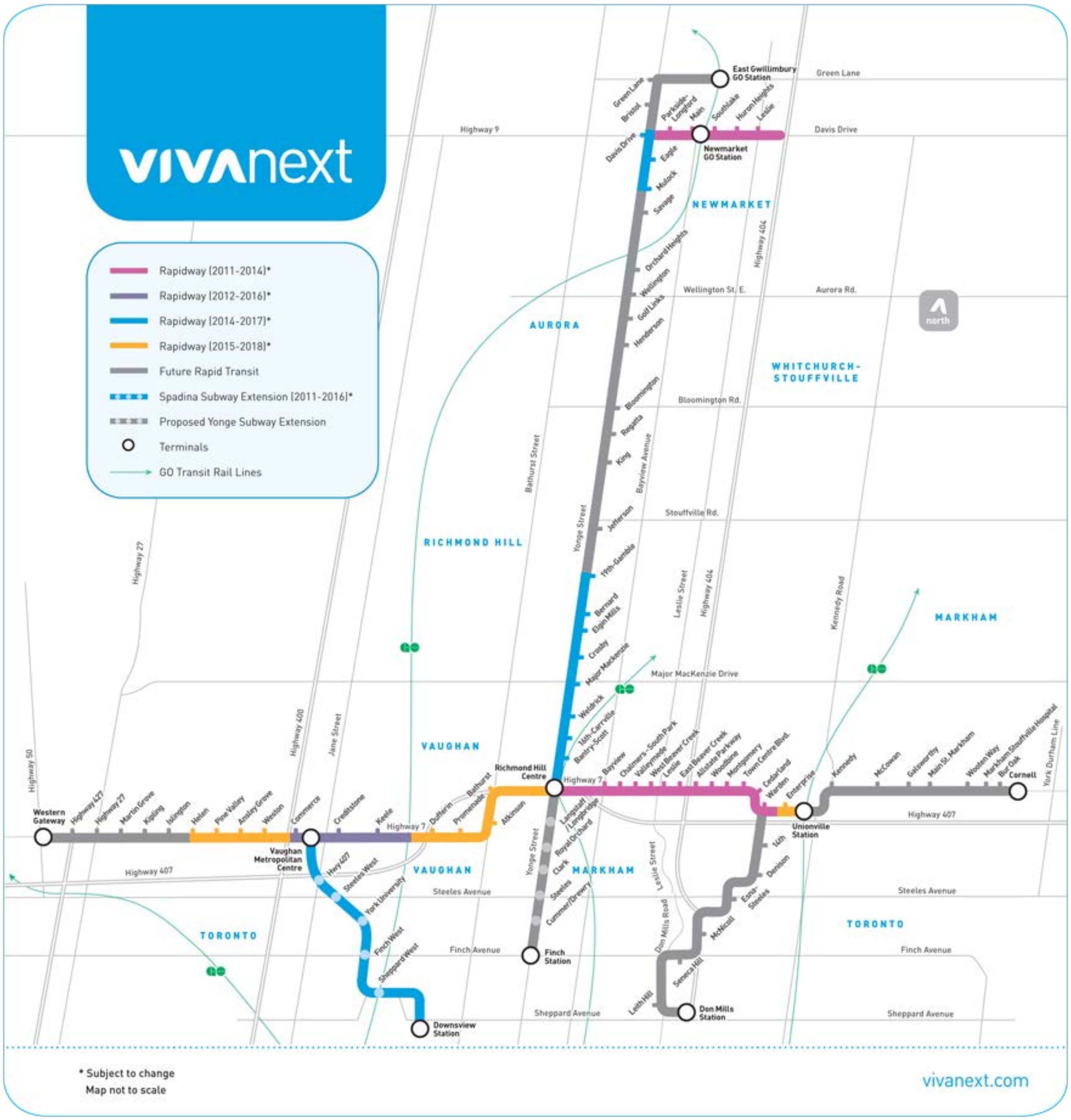
Every effort is made to avoid the relocations requirement as a first alternative, however, where direct conflicts are identified between the proposed transit projects and the existing natural gas pipelines, generally, the relocation of the gas pipeline is required. The specific routes chosen for the new pipelines are based on conceptual designs, at this time, and are not confirmed.

These routes, in most cases, are chosen for having the least economic impact while maintaining customer load and network capacity.

4. Capital Requirements

The estimated costs in the initial phases (2013 - 2016) will be approximately $18 million. In 2013, the costs are forecast to be approximately $5 million. Based on this 2013 experience, subsequent years are expected to range from $4 million to $6 million. The estimates are direct costs and cover all material, construction and labour, land acquisitions, and contingencies. For the years 2014 – 2016, Enbridge has budgeted an incremental $13M and see in Table 1.

Table 1: Capital Requirement Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
York Regional Rapid Transit Corporation	5,441	6,000	4,000	3,000



http://www.vivanext.com/system_map

SYSTEM INTEGRITY AND RELIABILITY FOR DISTRIBUTION ASSETS – OVERVIEW

1. The purpose of this evidence is to present the System Integrity and Reliability capital requirements for the 2014, 2015 and 2016 period. This exhibit provides the Ontario Energy Board (the Board) with a detailed breakdown and explanation of the various categories of capital expenditures and individual justifications for planned major programs and projects over $2 million and a listing of the projects less than $2 million over the forecast period in the following Schedules and Attachments. For System Integrity and Reliability, the capital categories address the requirements for replacement pipelines (both mains and services), the replacement and upgrade of measurement and regulating stations and other supporting programs such as Records Management

The System Integrity and Reliability Capital Requirements 2014 to 2016

2. The capital requirements for programs and projects related to System Integrity and Reliability as proposed have annual increases, over the base year, between 56% to 67%. These increases are a result of the need to address potential threats to the distribution system before they materialize as failures. The majority of these increases are related to the expansion of existing programs such as the acceleration of the AMP Fitting Replacement program and the need for incremental resources necessary to execute these programs. Table 1 provides the total capital requirements over the forecast period, the year over year variances and the variances relative to the base year.

Table 1: System Integrity and Reliability Capital Requirements and Variances to Base Year				
Description	Budget	Forecast Period		
	2013	2014	2015	2016
System Integrity and Reliability Totals ($000)	84,724	132,333	135,126	141,103
Variance Year Over Year ($000)	NA	47,609	2,793	5,977
Variance to Base Year ($000)	NA	47,609	50,402	56,379
Percentage Variance to Base Year (%)	NA	56%	59%	67%

Further detail on the capital requirements is provided below.

Purpose and Scope of Integrity and Reliability

3. System Integrity and Reliability consists of those programs, projects and activities focused on:
   - Maintaining the entire natural gas storage, transmission and distribution pressurized system at or above adopted standards for continued safe and effective operation (System Integrity);
   - Ensuring the dependable delivery of natural gas to Enbridge's customers and end-users (Reliability);

4. For the purpose of this evidence, the capital requirements of Storage operations are addressed under Exhibit B2, Tab 6, Schedule 1 while the balance of the System Integrity and Reliability capital requirements are addressed under Exhibit B2, Tab 5, Schedules 1 through 5.

Role of Pipeline Integrity and Engineering and Operations

5. The System Integrity and Reliability scope of work is managed by a number of departments with the Pipeline Integrity and Engineering Department taking the lead role in defining the standards, setting the priorities for related programs and projects and playing a direct role in some of the condition monitoring requirements such as the In-Line Inspection program. The Company's Operations Department executes the majority of the condition monitoring, upgrade and replacement programs and projects associated with the System Integrity and Reliability scope of work. The Storage Operations Department plays a parallel role for the above and below ground storage assets.

The Requirement for System of Integrity and Reliability Programs

6. A critical responsibility in managing a natural gas distribution system is to understand potential threats to the integrity and reliability of the system. Threats to system assets can manifest risks which if not appropriately managed, can lead to serious incidents. In general, risks associated with gas distribution assets occur when there is a loss of containment of gas from the system, when the system is operating above or below the intended design pressure range, or when there is a loss of supply of gas to any portion of the system. The System Integrity and Reliability capital requirements are required to identify, understand and mitigate these risks before an incident occurs.

7. Enbridge designs and operates its natural gas pipeline system in accordance with Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), in addition to all other applicable codes, standards and regulations. This regulation adopts the Canadian Standards Association code CSA Z662-11 Oil and Gas Pipeline Systems with amendments as defined in Section 2 of Ontario's Technical Standards and Safety

Authority (TSSA) Code Adoption Document (CAD), FS-196-12, dated November 1, 2012.

8. The most significant change from the 2007 to the 2011 version of the CSA Z662, and the corresponding 2008 and 2012 TSSA CAD was the requirement for the Company to apply Integrity Management processes to all distribution operating assets (previously limited to operating assets with a SMYS above 30 %). The Enbridge interpretation of this requirement is the need to analyze the entire storage, transmission and distribution system and its components, determine their suitability for continued service and remediate assets determined by the Company to have a risk of failure prior to failure.

9. Section 3.2 of CSA Z662-11, Pipeline System Integrity Management Program states as follows:

> Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clauses 10.3 and 10.5) for managing the integrity of the pipeline system so that it is suitable for continued service, including procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data. Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for

(a) assessing current potential risks;

(b) identifying risk reduction approaches and corrective actions;

(c) implementing the integrity management program; and

(d) monitoring results

10. The integrity management program approach adopted by the Company for all operating assets is further defined by the TSSA Oil and Gas Pipeline Systems Code Adoption Document, Section 2, paragraph 2 (8) , FS-196-12 (CAD), which through Section 2, paragraph 2 (15) of the CAD requires the inclusion of the

operating assets of distribution system operating below 30 % of SMYS, as defined by the CSA Z662 Clause 3.2 (which also includes Clause 10.3). In other words, the clause below also applies to the operating assets below 30 % SMYS according to the TSSA CAD :

> For the protection of the pipeline, the public and the environment, the operating company shall develop a pipeline integrity management program for steel pipelines with an MOP of 30% or more of the SMYS that complies with the applicable requirements of clause 3.2 of CSA Z662-11. The integrity management program shall include the following items:
>
> (a) a management system;
>
> (b) a working records management system;
>
> (c) a condition monitoring program, and
>
> (d) a mitigation program."

Further detail of the integrity management system approach required by the CSA Z662 code can be found in Annex N of that code.

<u>System Integrity and Reliability Programs and Projects</u>

11. The System Integrity and Reliability Programs and Projects have been grouped in the following categories:
    - Mains – Replacement
    - Service – Replacement
    - Stations – Upgrades and Replacements
    - Other

12. The mains replacement programs and projects include all capital requirements associated with the major account group for distribution mains or pipelines. This scope of work is summarized in the evidence at Exhibit B2, Tab 5, Schedule 2. These programs and projects are:

1. Miscellaneous Mains Replacement Program, (B2-5-2-1)
2. Compression Couplings Replacement Program, (B2-5-2-2)
3. Load Shed Program, (B2-5-2-3)
4. Maximum Operating Pressure Verification Program, (B2-5-2-4)
5. In-Line Inspection and Assessment Program, (B2-5-2-5)
6. Right of Way Mitigation Program, (B2-5-2-6)
7. Main Replacement Projects Under $ 2 million, (B2-5-2-7)

13. The service replacement programs and projects include all capital requirements associated with the major account group for distribution services, (the small diameter pipelines between the distribution mains and the customers sales station or meter and regulator). This scope of work is summarized in the evidence at Exhibit B2, Tab 5, Schedule 3. These programs and projects are:

    1. Miscellaneous Service Replacement Program, (B2-5-3-1)
    2. AMP Fitting Replacement Program, (B2-5-3-2)
    3. Compression Outlet Service Tee Replacement Program, (B2-5-3-3)
    4. Sewer Safety Program, (B2-5-3-4)
    5. Service Replacement Projects Under $ 2 million, (B2-5-3-5)

14. The Station Replacement and Upgrade programs and projects include all capital requirements associated with the major account group for measurement and regulating stations. The stations within this scope include all gate station, district stations and major sales stations. This scope of work is summarized in the evidence at Exhibit B2, Tab 5, Schedule 4. These programs and projects are:

1. Gate Stations Programs and Projects, (B2-5-4-1)
2. District Station Replacements and Upgrades, (B2-5-4-2)
3. Commercial and Industrial Low Pressure Regulator Stations, (B2-5-4-3)
4. Paper Chart Recorder Replacement Program, (B2-5-4-4)
5. Station Replacement and Upgrade Projects Under $ 2 million, (B2-5-4-5)

15. The Other System Integrity and Reliability Programs include the Meter and Regulator Replacement Program (B2-5-5-1), the Distribution Records Management Program (B2-5-5-2), and the Extension of the Envision Program (B2-5-5-3). The Meter and Regulator Replacement Program is the continuation of ongoing replacement of small meters and the associated downstream regulators at residences and small commercial locations. The Distribution Records Management Program is a recent program designed to collect and enhance necessary distribution asset information. Finally, the Envision Extension project is the capital requirement for the continuation of the services provided for work and asset management capabilities.

16. Table 2 provides the major categories of capital requirements for the base year and over the forecast period.

Table 2: System Integrity and Reliability Capital Requirements ($000)				
	Budget	Forecast		
Description	2013	2014	2015	2016
Mains – Replacement	18,237	24,604	24,098	22,110
Service – Replacement	17,814	21,118	25,011	41,216
Stations – Replacement and Upgrades	15,767	23,990	26,442	24,517
Other System Integrity and Reliability	32,906	41,808	42,650	35,810
System Integrity Direct Resource Cost	15,330[1]	20,813	16,925	17,449
Totals	84,724[2]	132,333	135,126	141,103

17. The overall capital requirements of the forecast period are required to proactively address identified risks to the distribution system. Several of these risks are historically known and addressed through ongoing programs such as the Miscellaneous Main and Service Replacement Programs or the Meter and Regulator Replacement Program. Emerging or incremental risks have been identified through the asset planning process and addressed through recent or incremental programs such as the AMP Fitting Replacement Program or the Maximum Operating Pressure Verification Program. Further details on the base

[1] 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. That is the level of spending on this category of costs to be used for comparison purposes within 2014 to 2016.
[2] Ibid.

programs and the newer programs are presented in evidence at Exhibit B2, Tab 5, Schedules 2 through 5.

18. The capital requirements identified above cover all direct labor, material and contract resources requirements necessary to define, design and execute the System Integrity and Reliability programs and projects. A conscious decision was taken by the Company to not include contingency amounts within these programs. This is of significance when considering such Integrity and Reliability programs as the Maximum Operating Pressure Verification program, the In-Line Inspection program and the Process Hazards Assessment program for measurement and regulating stations. Although the expected costs for the design and execution of these scopes is included in capital requirements for the forecast period, any significant outcomes from these programs is not. For example, if an In-Line Inspection and Assessment project for a particular pipeline results in a finding that requires the replacement of a major section of the pipeline, no capital has been provided for over the forecast period. In addition, no contingency capital has been identified and included in the capital forecast for significant events such as those resulting from extreme environmental events or currently unknown threats that may arise over the forecast period.

CAPITAL REQUIREMENTS - REPLACEMENT MAINS

Summary

1. Replacement main programs and projects are ongoing activities that include replacing existing pipelines and associated valves and fittings that are either at or near the end of their useful life, or are being replaced to address integrity and reliability risks. This evidence also includes associated programs needed to assess and enhance the integrity or reliability of these pipelines.

2. The Replacement Mains capital requirement for the period of 2013–2016 is summarized in Table 1. See Table 2 for detailed breakdown of programs included.

Table 1: Capital Requirements ($000s)

2013	2014	2015	2016
18,237	24,604	24,098	22,110

3. The following programs and projects are include with this evidence:
    a. Miscellaneous Replacement of Mains
    b. Compression Couplings
    c. Load Shed Program
    d. Maximum Operating Pressure Verification
    e. In-Line Inspection and Assessment Program
    f. Right of Way Easement Monitoring Program
    g. Replacement Main Projects Under $ 2 million

4. The Miscellaneous Replacement Mains capital requirement is based on the general need to replace distribution pipelines that are identified within the forecast year. These replacement main projects include pipeline segments that need to be

replaced across the system, identified through the ongoing leak survey program, through leaks called in by the public or through previously unidentified third party municipal work. The Miscellaneous Replacement Mains requirements are also identified through routine Enbridge maintenance and other condition monitoring programs and potentially from impacts on the pipelines from environmental conditions, such as excessive soil erosion or movement. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 1.

5. The Compression Couplings Program is needed to address the risks associated with this previously pipeline fitting. Compression couplings are a pipeline fitting installed to mechanically join and seal pipe segments and fittings together in the pipeline distribution system. These fittings were used historically to complete difficult pipe fitting work at “tie-in” locations where valves, tees and other pipe fittings were joined together in areas where traditional welded construction techniques were not practical or available at the time. These fittings can pull apart and/or lose their seal when excavations occur in close proximity. In such circumstances, pipeline remediation is required to ensure the continued integrity of the pipeline. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 2.

6. The Load Shed Management Program is needed to ensure that the Load Shed Zones defined by Enbridge are practical and available. Load Shed Zones (LS Zones) are an industry best practice that involves the controlled removal of gas service from large areas of customers when there is a supply disruption. The goal of load shedding is to minimize widespread system outage in the event of limited supply or network disruption. Replacement main projects are required to replace segments of pipelines with isolation valves used to set up the LS Zones. This capital

requirement is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 3.

7. The Maximum Operating Pressure (MOP) Verification initiative involves the quality assurance verification of the maximum operating pressure of Enbridge's 3500 km highest pressure pipelines. The maximum operating pressure (MOP) is the maximum pressure at which a pipeline is qualified to be operated. Replacement main projects are required when field verification identifies pipeline segments, valves or other fittings that must be replaced to maintain and ensure the MOP of the pipeline system is maintained. Although Enbridge has not included any capital requirement for potential major replacement projects resulting from this verification program there is a possibly that capital will be needed within the forecast period if any pipeline MOP verification yields the need for a permanent reduction in the maximum operating pressure. This program is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 4.

8. The In-Line Inspection (ILI) and Assessment Program includes the capital requirements for retrofitting targeted existing pipelines operating above 20 % of their specified minimum yield stress (SMYS) to accommodate in-line inspection tools or the installation or replacement of valves and other fittings to enhance the safety and integrity of the distribution system. This capital requirement also includes the need for investigative excavations and minor capital repairs. As noted in paragraph 7 above, Enbridge has not included any capital requirement in the forecast period to address the potential for significant pipeline replacement requirements resulting from the ILI and Assessment Program. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 5.

9. The Right of Way Easement Monitoring Program identifies the capital necessary for the deployment of technology intended to enhance the Company's ability to monitor for and halt unauthorized actives over or around specific pipelines before incident occur. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 2, Attachment 6.

10. Other replacement main projects with a total capital requirement below $ 2 million over the forecast period are summarized at Exhibit B2, Tab 5, Schedule 2, Attachment 7.

11. Table 2 summarizes all of the direct capital requirements for the programs and projects associated with the replacement of pipelines with the Company's distribution network.

Table 2: Capital Requirements Breakdown ($000s)

Table 1: Mains - Replacement				
Description	Budget	Forecast Period		
	2013	2014	2015	2016
Misc. Replacement Mains	4,582	5,388	5,866	5,088
Compression Couplings	1,100	1,622	2,040	2,061
Load Shed Planning Program	1,000	1,145	1,171	1,194
Maximum Operating Pressure Verification Program	794	3,296	3,397	3,195
In Line Inspection and Assessment Program	6,861	11,000	8,900	8,502
Right of Way Easement Monitoring Program		581	935	1,770
Pipeline Replacement Projects Less Than $ 2 million	3,900	1,572	1,790	331
Total	18,237	24,604	24,098	22,110

Witnesses: L. Lawler
J. Sanders

MISCELLANEOUS MAIN REPLACEMENTS

1. Miscellaneous Replacement Main projects are an ongoing group of projects that includes replacing existing pipelines and associated valves and fittings that are either at or near the end of their useful life. These projects are typically identified and initiated within the year that they are completed.

2. Generally, Miscellaneous Replacement Main projects are smaller in scope and cost and are initiated from a number of sources throughout the year. These include identification through the leak survey program, leaks called in by the public or as a result of unplanned direct conflicts with third party municipal works. The Miscellaneous Main Replacement projects are also identified through routine maintenance or condition monitoring programs where they may be either exposed due to environmental conditions, have excessive external corrosion or may have fittings or appurtenances attached that are deteriorating or creating potential hazards.

3. The Miscellaneous Replacement Mains capital requirement for the period of 2014 to 2016 is summarized in Table 1.

Table 1: Capital Requirements ($000s)

	Budget	Forecast		
	2013	2014	2015	2016
Misc. Replacement Mains	4,582	5,388	5,866	5,088

4. The required capital for the forecast period is based on historical spends and is anticipated to continue at typical levels throughout the forecast period.

COMPRESSION COUPLING PROGRAM

Summary

Compression couplings are a pipeline fitting installed to mechanically join (not welded) and seal pipe segments and fittings in the existing distribution system. Enbridge installed compression couplings on steel mains prior to 1991. Compression couplings can fail when the pipe or fitting connected to the coupling is pulled out by outside mechanical or geotechnical forces or by the pressure in the pipeline when the required restraint is removed. This will lead to the loss of containment (or gas leakage) and potential injuries to workers or the public.

The Compression Coupling Program is the expansion beginning in 2013 of an existing program intended to further reduce the risks associated with the failure of compression couplings.

The existing program involved records investigations when locate requests are received identifying construction activities in the vicinity of gas mains that meet specific criteria, as well as remediating Compression couplings that are found during pipeline construction. The Compression Coupling Program has the following incremental features:

- Search all records for compression couplings and show these fittings and their restrained/unrestrained status in GIS.
- Excavate and expose targeted known compression couplings with unknown restrain/unrestrained status if necessary.
- Proactively excavate and expose the suspect pipelines at locations that have a potential of having compression couplings (no existing record of compression

couplings) with insufficient pull out resistance and mitigating through restraining or removal.

- The use of above ground locating tools and existing in-line inspection data verification.

As other utilities undertake infrastructure improvements projects, like replacing their aging buried infrastructure or burying aging overhead facilities, there is an increased risk of compression coupling disturbance prior to remediation.

The Compression Coupling Program is a more pro-active approach to eliminating a known risk on the distribution system particularly for those in the excavating community who do not call for locates or do not wait for locates to be completed prior to excavating. By confirming the location and status of compression couplings, targeting areas that have a high potential of their existence (regardless of their existence in records), remediating them when found, and plotting all results in GIS, this program will work towards eliminating the risk that these assets pose.

The capital requirements for the program over the forecasted period are shown in Table 1 below:

Table 1: Capital Cost Summary ($000)

	Budget	Forecast		
	2013	2014	2015	2016
Program Cost	1,100	1,622	2,040	2,061

Background

Compression couplings are a pipeline fitting installed to mechanically join (not welded) and seal pipe segments and fittings in the existing distribution system (see Figure 1 for an illustration of a compression coupling). As per industry standard, Enbridge installed compression couplings on steel mains. Given the concerns about compression couplings not having sufficient pull-out resistance, Enbridge discontinued installing these fittings in 1991. Compression couplings can fail when the pipe or fitting connected to the coupling is pulled out by outside mechanical or geotechnical forces or by the pressure in the pipeline when the required restraint is removed. This will lead to the loss of containment (or gas leakage) and potential injuries to workers or the public.

Figure 1: Compression Coupling

For example, in 1995, in the course of performing work on gas plant, a compression coupling failed to have sufficient pullout resistance. This failure resulted in injuries and property damage. As a result the Ministry of Labour ordered Enbridge to provide information and instructions to workers when the presence of compression couplings with insufficient pull out resistance is likely. In response, Enbridge developed policies and procedures involving any work that is to be completed in the vicinity of these fittings.

Compression couplings with insufficient pull out resistance are considered to be restrained when a steel pressure containment sleeve (colloquially a pumpkin) has been welded around it (See Figures 2 and 3 for images of these restrained and unrestrained Compression Couplings). The hazards associated with excavating in the vicinity of unrestrained compression couplings will remain in place until all compression couplings with insufficient pull out resistance are either removed or restrained.

When work is performed when exposing or when potentially creating a point of thrust on all Extra High Pressure (XHP) mains, all High Pressure (HP) mains, and Intermediate Pressure (IP) mains NPS 4 and greater, records investigations are completed to ensure that there are no unrestrained Compression couplings in the vicinity of the work to be performed. This information is provided to both third parties and Enbridge work crews as required.

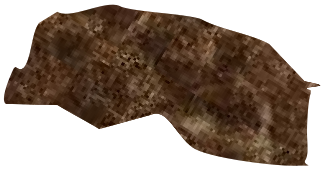


Figure 2: Unrestrained Compression Coupling

Figure 3: Restrained (pumpkined) Compression Coupling

Operational challenges occur when either the records do not show the compression coupling, or do not show whether or not the compression coupling has been restrained.

An example of this operational challenge occurred in 2012 at Martin Grove Rd & Burnhamthorpe Rd. Five NPS 12 compression couplings operating at 175 psi were found during third party work. Records for this intersection only indicated the existence of one compression coupling. All five compression couplings were removed by replacing the sections of main at this intersection. These are illustrated in Figures 4-6 below.

Figure 4: Construction reveals compression couplings at Martin Grove & Burnhamthorpe Rd

Figure 5: Closer view

Figure 6: Remediation completed

The situation at Martin Grove Rd & Burnhamthorpe Rd shows the potential for the occurrence of a serious incident resulting in the loss of containment and potential for injury to workers and the public. This reinforces Enbridge's decision to focus on finding high potential locations for compression couplings that are not necessarily identified in the existing Enbridge records. High potential locations are based on tie-ins and valves installed before 1965 and tacit knowledge from field personnel of known operational practises.

As other utilities undertake infrastructure improvements projects, like replacing their aging buried infrastructure or burying aging overhead facilities, there is an increased risk of compression coupling disturbance prior to remediation.

The current practice of conducting compression coupling investigations through record searches at the locate stage for external parties and restraining the fittings on an as required basis, is effective when third party excavators call Ontario One Call for locates. Since Enbridge is aware that excavators do not comply with legislation requiring them to call Ontario One Call before commencing an excavation 100% of the time, Enbridge is aware that the Company cannot protect third party excavators from the risk of compression couplings with insufficient pullout resistance in every instance. Enbridge identified a need to be more proactive to reduce the risk associated with compression couplings on a risk prioritized basis.

Enbridge has completed several studies to find compression couplings in the system in the past, but these studies were limited to records searches and documentation only. Field verification has not been performed to validate their status (i.e. restrained or unrestrained), nor has there been a focus on finding the unrecorded couplings.

Program Description

The Compression Coupling Program is a pro-active approach to eliminating a known risk on the distribution system.

The program will confirm the location and status of compression couplings, targeting areas that have a high potential of their existence (regardless of their existence in records), remediating them when found, and plotting all results in GIS, this program will work towards eliminating the risk that these assets pose.

The program has a multi-pronged approach:

- Search all records for compression couplings and show these fittings and their restrained/unrestrained status in GIS.
- Excavate and expose targeted compression couplings with unknown restrain/unrestrained status to identify status and mitigate through restraining
- Proactively excavate and expose the suspect pipelines at locations that have a high potential of having compression couplings with insufficient pull out resistance and mitigation through restraining or removal. These include locations where compression couplings are not currently indicated in the records, but would be anticipated due to common practises during the years these fittings were used. These would be risk prioritized based on defined criteria.
- Augmenting field validation through the use of above ground locating tools and existing in-line inspection data verification.

In 2013, Enbridge is targeting 55 locations within Toronto's old vintage high pressure steel pipeline system. These locations were identified as the highest potential to have unrestrained compression couplings. The program will be extended over the forecast period and beyond to incorporate all other high pressure steel mains across the Enbridge system.

Enbridge evaluated four alternatives prior to selecting the preferred alternative. The alternatives considered were:

1. Continue with the existing program,
2. Alternative 1 plus record all compression couplings in GIS,
3. Alternative 2 plus validate the status of all compression couplings on a risk prioritized and opportunistic basis and excavate to find all potential compression couplings on a risk prioritized and opportunistic basis,
4. Alternative 1 plus replace large sections of vintage pipe where the likelihood of having compression couplings installed is high.

Alternative 1

This alternative maintains the current program of performing records searches when work is planned in the vicinity of gas mains with the potential for unrestrained compression couplings and remediating the compression couplings when necessary. This alternative was rejected because it did not improve the safety and reliability of the distribution of the system and it continues to expose third party excavators who do not call Ontario One Call for locates to the risk of an unrestrained compression coupling.

Alternative 2

This alternative augments the current program of performing records searches when work is planned in the vicinity of gas mains with the potential for unrestrained compression couplings and remediating the compression couplings when necessary, by including the inputting of known compression coupling locations into GIS. While this alternative does document known compression coupling locations in GIS, it provides little improvement in the safety and reliability of the distribution system, and like alternative one, continues to expose third party excavators who do not call Ontario One Call for locates to the risk of an unrestrained compression couplings. Therefore this alternative was rejected.

Alternative 3

This alternative augments the current program of performing records searches when work is planned in the vicinity of gas mains with the potential for unrestrained compression couplings and remediating the compression couplings when necessary by:

- including the inputting of known compression coupling locations into GIS,
- validating the status of all compression couplings on a risk prioritized and opportunistic basis and excavate to find all potential compression couplings on a risk prioritized and opportunistic basis, and
- Excavating to find all potential compression couplings that are currently unknown and not in our records on a risk prioritized and opportunistic basis.

This alternative is the preferred program which provides significant improvement in safety and reliability compared with the other alternatives.

Alternative 4

This alternative involves the replacement of large sections of vintage pipe where the likelihood of having compression couplings with insufficient pull out resistance installed is high, with a new pipeline system. This alternative does provide for safety and reliability, however, it requires large amounts of capital which may result in the unnecessary removal of pipeline assets.

Enbridge has elected to manage the compression coupling risk through the implementation of Alternative 3. This is the preferred alternative because it is a comprehensive plan to identify and mitigate all compression couplings in the system, known and unknown, starting with the highest risk, but also addressing these situations opportunistically when Enbridge or third party work is taking place. The approach that this program takes is proactive and targeted. Specific locations (valves, tie-ins) where the probability of having compression couplings is high will be targeted for remediation on a risk prioritized and opportunistic basis. For locations where there are clusters of compression couplings, sections of main for replacement will be identified and mitigated in a risk prioritized manner.

The Compression Coupling Program will result in having records that are verifiable, traceable and complete, consistent with industry best practise.

Capital Requirements

The Compression Coupling Program is an on-going remediation program over approximately 10 years.

Table 2 below identifies the Capital outlay for the program from 2014 to 2016.

Table 2: Capital Cost Summary ($000)				
	Budget	Forecast		
	2013	2014	2015	2016
Program Cost	1,100	1,622	2,040	2,061
Units	55	78	100	100

LOAD SHED PLANNING, CAPITAL PLAN 2014 – 2016

Summary

In the event of a widespread or significant natural gas supply disruption (loss of supply or reduced pressure), demand on the system needs to be removed in a controlled manner from the network to sustain supply to as many customers as possible. This (load shedding) is achieved by closing valves to predefined area(s) of the network. This will prevent a cascading distribution system failure where the loss of supply could result in a random and unpredictable outage to a much larger number of customers. This capital request is for funding to install additional valves in the network to create additional areas that can be isolated.

The estimated capital requirements for 2013-2016 is presented in Table 1, below.

Table 1: Capital Spend for Load Shed Valves ($000)

Description	Budget	Forecast Period		
	2013	2014	2015	2016
Load Shed Zones	$1,000	$1,145	$1,171	$1,194

Background

At Enbridge, Load Shed (LS) Planning defines isolatable areas of the gas distribution network, called LS Zones, which typically have less than 10,000 customers and require 10 or less valves for isolation. In February of 2011, a failure of TransCanada's mainline in Northern Ontario resulted in supply disruptions in the Greater Toronto Area. During this emergency, Enbridge determine that the isolation of significant areas of the gas network may have been required as a contingency in case TransCanada was unable to return to normal operation. Potential mitigation options at that time and for this scale of disruption, included shutting-in entire towns and cities well in excess of 100,000 customers. This incident led Enbridge to evaluate the need for smaller predefined LS zones. In 2012, Enbridge surveyed the Canadian Gas Association to evaluate current load shed planning methodologies and practices used in industry, including the number of customers and the number of valves. Based on this above and recent history, LS planning was formalized at Enbridge in 2012 to define smaller and more manageable areas.

2012 saw the completion of a LS study where LS policy and processes were developed for implementation in 2013. LS Zones were identified based on existing infrastructure and currently 48% of customers are within LS Zones. Through this analysis, areas in the distribution network were identified that did not meet LS Zone criteria. These were often highly concentrated urban areas (i.e. downtown Toronto) where the size and integration of the distribution network makes system isolation challenging. Starting in 2013 and beyond, valves will be installed at key locations throughout the distribution network to increase and improve the network coverage of LS Zones. Any future modification to the distribution system network will also consider the integrity of the now defined LS Zones and customer counts to ensure sustainability.

Policies and procedures related to LS were developed and 147 LS Zones were identified based on existing infrastructure.

Description of Work

In the first quarter of 2013, LS policy and procedures were incorporated into Company manuals with training rolled out to pertinent staff. This will ensure that any work on the system either maintains or improves existing area isolation options. In 2013, Enbridge is installing valves at strategic locations to create new LS Zones. These locations will allow the Company to manage disruptions on key system infrastructure with potential for large customer impact.

It is planned to install valves for LS Planning at an average rate of approximately 10 to 15 valves per year within the next 15 years. The first area that will be targeted is presented in Figure 1, which is the area that runs along the north shore of Lake Ontario, east of the Don Valley and west of the Rouge Valley. Currently within this area the only load shed options are to isolate all 90,000 customers or the 10,000 customers within the existing LS zone.

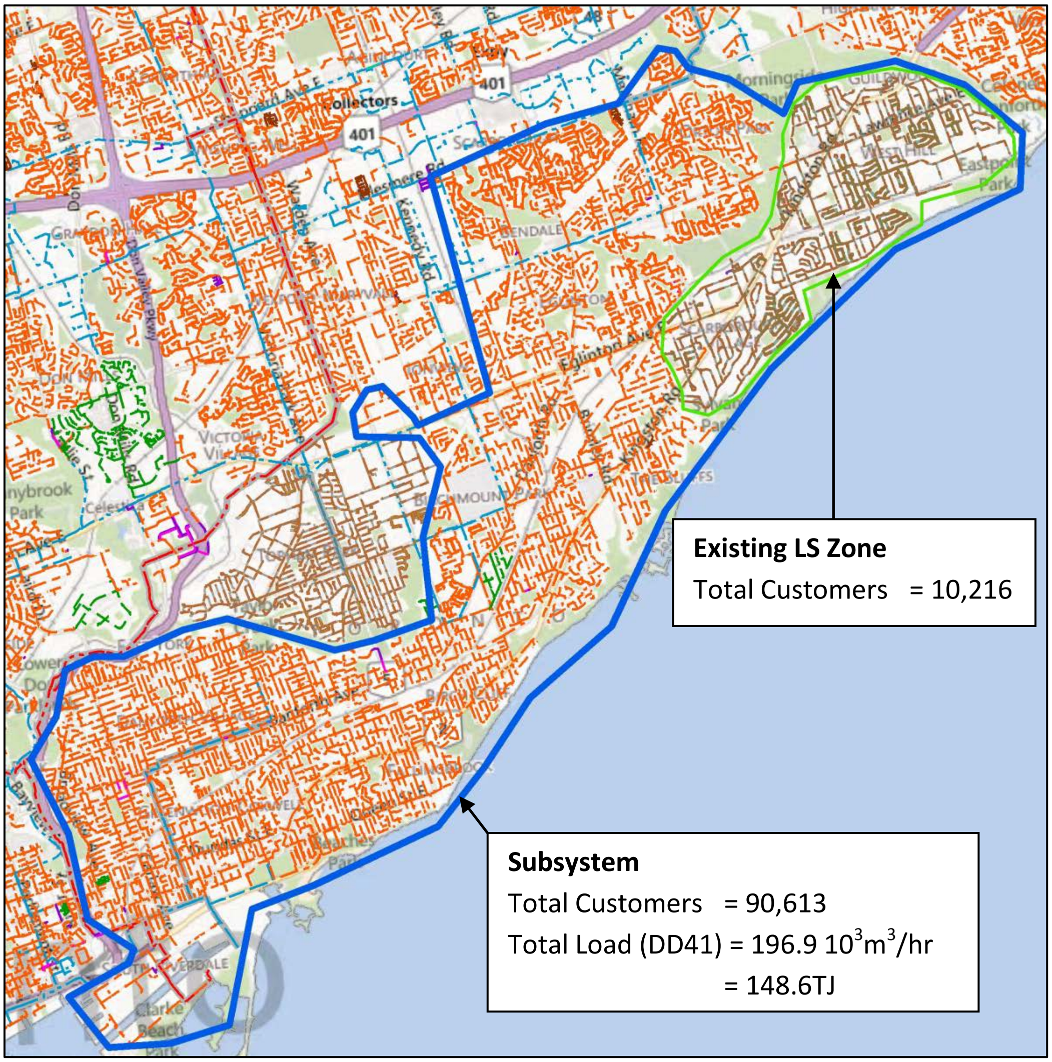


Figure 1: Subsystem East of the Don Valley

Figure 2 shows 5 proposed valve locations and the resulting 3 new LS Zones that will be created in this area. Valve locations are indicated by yellow circles, and the highlighted red areas indicate new isolatable areas. The creation of these zones will capture approximately 70% of the customers in the subsystem identified in Figure 1, and requires an estimated capital of $325,000.

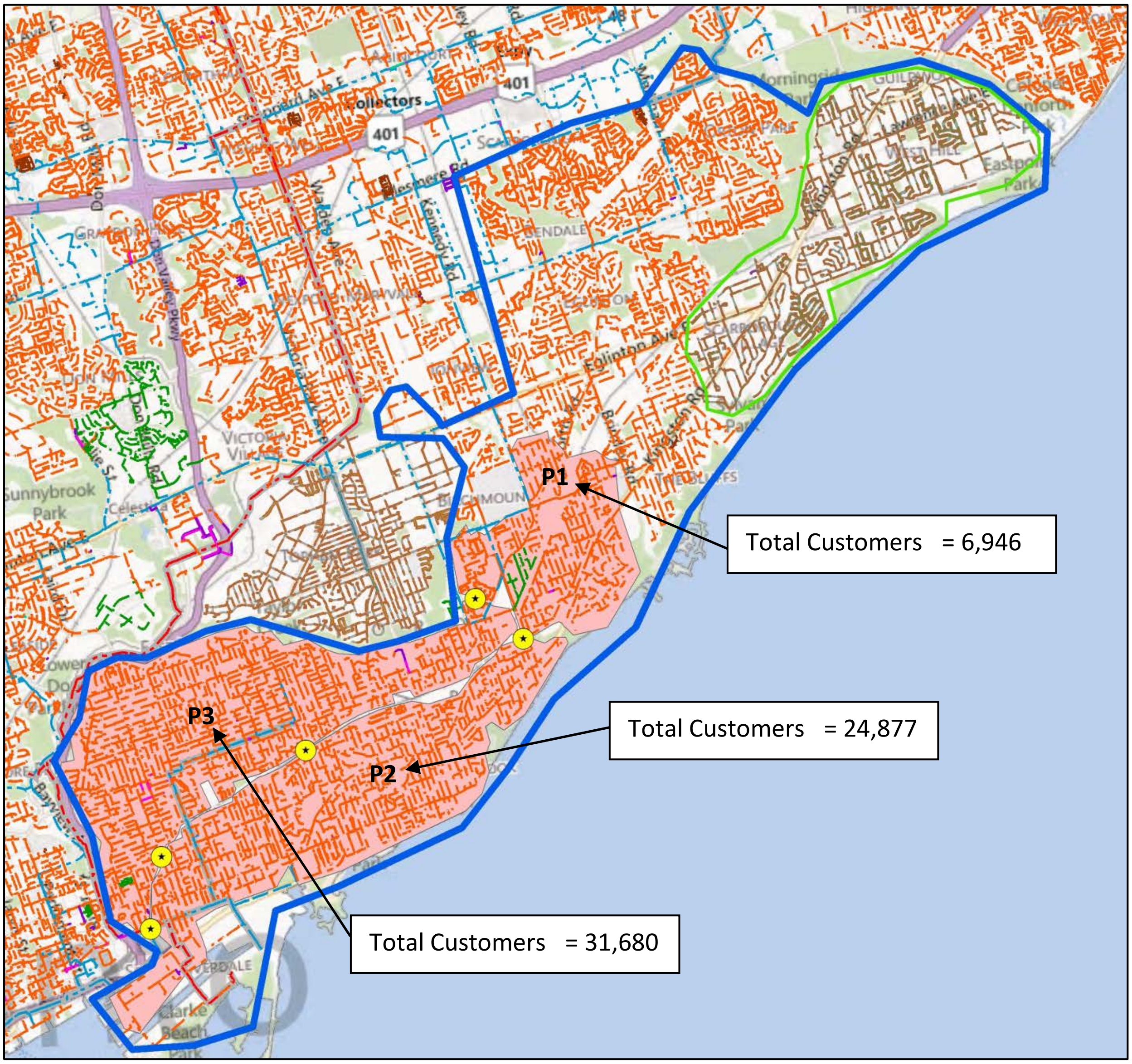


Figure 2: Proposed Valve Location and New LS Zones

Additional LS Zones will be added in downtown Toronto with a total project cost of $1M for 2013. Within the next 15 years valve locations will be identified and installed based on LS Planning.

MOP VERIFICATION PROGRAM

Summary

The purpose of this program is to enhance the safety and reliability of Enbridge's gas distribution system through comprehensive records analysis and field investigation, in order to verify the maximum operating pressure (MOP) of Enbridge's highest pressure pipelines. This program is also designing and establishing new and incremental methods for the identification and maintenance of the MOP of these pipelines. MOP is the maximum operating pressure at which a pipeline is qualified to operate. The processes, technology, and governance required to capture and manage the asset records to verify the MOP are covered in the Distribution Records Management (DRM) program.

The 2010 San Bruno incident and the continued critical importance of MOPs to the safety and reliability of Enbridge's highest pressure pipelines prompted Enbridge to examine its existing MOP process, including record keeping. In 2012, Enbridge conducted the first phase of the MOP verification project on approximately 500 km of its highest pressure pipelines. This phase resulted in a verification of the MOP of these pipelines and also identified follow up issues resulting in field investigation, pipeline remediation and mitigation measures. These findings confirmed to Enbridge that it is prudent to move beyond the first phase and continue with a broader MOP verification program of its approximately 3500 km of extra-high pressure pipelines.

The capital requirement for this program over the 2014-2016 forecast period averages $3.3 million per year for a total of $9.9 million and is summarized by year in Table 1.

Table 1: Capital Cost Summary ($000)			
Budget	Forecast		
2013	2014	2015	2016
794	3,297	3,397	3,196

Background

The age of Enbridge's highest pressure pipelines spans many decades. Extra-high pressure pipelines operate with MOPs greater than 175 psi. Pipelines historically have been and continue to be designed and constructed in accordance with the relevant standards, codes and regulations applicable at the time of their installation. Standards for recording pipeline properties and determining MOPs have evolved over time, with records capturing differing levels of detail at different times. The MOP of a pipeline is the maximum pressure at which piping is qualified to operate, by the CSA Z662-11 Code and applicable Ontario regulations.

Following the 2010 San Bruno, California incident, and the review of the investigative and technical findings, as well as the responses of industry, Enbridge concluded that an assessment of the systems and processes used to record and maintain the MOPs s for its extra high pressure pipelines was a prudent initiative. One of the central highlights in the findings and recommendations of the United States National Transportation Safety Board (NTSB) investigation reinforced that incomplete pipeline records and/or a lack of MOP verification can be significant contributing factors leading to a serious incident. The NTSB further concluded that this risk should be mitigated through corrective actions such as MOP Verification and the ongoing maintenance of the MOP (Refer to NTSB Report: NTSB/PAR-11/01, PS2011-916501 adopted August 30, 2011).

In addition, the U.S. Department of Transportation Pipeline & Hazardous Materials Safety Administration (PHMSA) issued advisory bulletins (Jan 10, 2011 PHMSA Advisory Bulletin and May 7, 2012 PMHSA Advisory Bulletin) which require U.S. operators to verify and report that the MOP determinations for their pipelines are supported by reliable records. Enbridge now considers this to be industry standard.

As a prudent operator, Enbridge concluded that it was necessary to initiate a phased and targeted verification of the MOP of its highest pressured pipelines to confirm that reliable records continue to support the MOPs, now and for the operating life of these pipelines.

In 2012, the first phase of the program covered approximately 500 km of Enbridge's pipelines. This involved a comprehensive review and analysis of records (over 750,000 pages), performing field investigations and remediation, verifying MOPs, and the initiation of a process for maintaining these verifications. The results of the first phase in 2012 confirmed to Enbridge that it is prudent to continue with a program to verify and maintain the MOP of the highest pressure pipelines. The results of the first phase ranged from no action being required to lowering a pipeline's pressure. Specific examples of the more significant findings and resulting actions from the first phase include:

- Unsuitable pressure test records necessitating the installation and commissioning of a pressure regulation station;

- Inaccurate installation records indicating fittings not meeting operating pressure requirements which required field verification or replacement; and
- The interim lowering of operating pressure of pipelines due to insufficient pipeline information and the acquisition of new information about existing pipelines.

Building on the program work performed in 2012, and the findings from that work, Enbridge will conduct a multi-year (2013 to 2019) program to continue to verify the MOP of its approximately 3500 km of extra-high pressure pipelines. The pace and extent of the next phases of the program will be informed by the ongoing findings of the project and adjusted accordingly.

In 2013, the MOP verification methodology and process is being enhanced and is being applied to 550 km of pipelines.

Description of Work

Continuing at a pace similar to 2012 & 2013, the 2014 verification is planned to address 525 km, with an additional 600 km of pipelines are planned for verification in each of 2015 and 2016.

The MOP project work for 2014 through 2016 comprises the following,

- Records Assessment & Pipeline Component Database – As part of the DRM initiative, consolidation and review of records of the pipelines under review. This review includes records relating to the installation, maintenance and condition of the pipeline. Required information will be extracted from the relevant records and captured into a database of pipeline component attributes which will considerably enhance and improve the quality of access to a baseline of this information for current and future use, for any and all activity with respect to these pipelines for their lifetime.

- Field Investigation - Where necessary, field investigations will be conducted. Any issues identified will be remediated.
- Engineering Assessment and MOP Verification - Confirmation of the MOP for the targeted pipelines will be performed. Evaluation of pipeline record quality, all pipeline components, material properties, pressure test history, and the operating and condition history of the pipelines in a comprehensive manner will be performed to assess and ensure the appropriateness of the MOP. Requirements for verification, remediation and/or mitigation will be established.
- Remediation and Mitigation – Requirements for remediation or mitigation work, as defined within the engineering assessments, will be designed, planned and conducted through the Mains Replacement program.
- Records Enhancement - Planned work on extra-high pressure pipelines will be leveraged to gather pipeline information from the field and generate new records based to meet Distribution Records Management principles, as described in the DRM evidence.
- Records Management - The engineering assessment reports, along with all relevant records, will be scanned and stored in Enbridge's records management system.
- Ongoing Records and MOP Maintenance – This project will also design, refine and implement enhancements to Enbridge's operations to strengthen controls in order to maintain a baseline of MOP verification going forward. Together with the establishment and maintenance of baseline records through DRM, the maintenance of an up-to-date MOP record will be easily accessible over the life of the pipeline. This will ensure that any future

relevant activity involving these pipelines need only access the baseline record, and there will be no need to perform any further review and assessment of historical records behind that baseline.

Capital Requirements

There are two categories of work and costs for this initiative. The first category is for the Project Resources and Infrastructure to perform the MOP verifications and to establish a sustainable infrastructure for maintaining verifications into the future. The second category involves fieldwork to investigate and confirm pipeline properties.

The estimated costs for these categories of work in 2014, 2015, and 2016 are provided in the Table 2.

Table 2: Capital Cost Summary ($000)

	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Project Resources & Infrastructure	794	1,407	1,237	1,036
Field Verifications	--	1,890	2,160	2,160
TOTAL	794	3,297	3,397	3,195

Note that costs associated with the search and consolidation of historical records, capturing of data into the pipeline component database, and scanning of records for storage into Enbridge's records management system are a dependency for this program, and are included in the DRM program.

In addition, note that any modifications to the pipelines that may be deemed necessary for remediation purposes will be performed by the Mains Replacement Program. Any associated costs are not included in these estimates.

These cost estimates are based upon the results of the first phase of this program, from 2012 and are informed by the methodology enhancements identified for 2013 and beyond. The 2013 budget for this initiative was established prior to project planning and was significantly under-estimated. The 2013 capital budget of $794K was intended only for Project Resources and Infrastructure, and no budget allocation was made for Field Verifications.

Note that the 2013 Forecast is now $2.1 million, significantly higher than budget as per Table 3. Project Resources and Infrastructure are now based upon a more thorough estimate, using experience gained from the 2012 pilot in conjunction with plans and methodology enhancements for 2013 and beyond. Field Verifications are now included in the forecast, and are also based upon the results and experience from the 2012 first phase. In 2013, 550 km are scheduled for verification.

Table 3: 2013 Budget vs. Forecast ($000)

	Budget	Forecast
DESCRIPTION	2013	2013
Project Resources & Infrastructure	794	1,134
Field Verifications		1,000
TOTAL	794	2,134

A more detailed breakdown of the cost estimates for 2014 through 2016 can be found in Table 4.

Table 4: Cost Estimate Detail ($000)			
	Forecast		
DESCRIPTION	2014	2015	2016
Project Resources & Infrastructure	1,406	1,237	1,035
MOP Verification:			
Engineering Staff Costs	380	392	370
Fieldwork Planning & Mgmt Staff	305	305	305
Sustainable Infrastructure:			
Process Mgmt Staff Costs	119	90	60
Process Mgmt Consulting Fees	113	84	56
Change Mgmt Consulting Fees	135	100	68
Data Mgmt Consulting Fees	113	85	55
Program Mgmt Consulting Fees	241	181	121
Field Verifications	1,890	2,160	2,160
Pipeline Sample Testing	1181	1350	1350
Verification Excavations	709	810	810
TOTAL	3,296	3,397	3,195

ILI AND ASSESSMENT PROGRAM

Summary
The In-Line Inspection (ILI) and Assessment Program for Pipelines Operating over 20% Specified Minimum Yield Strength (SMYS) is an ongoing program, the scope of which has been expanded to facilitate Enbridge's ability to understand and manage the condition of these important backbone pipelines, as is required by Technical Standards and Safety Authority (TSSA) Code Adoption Document (CAD) Fuels Safety (FS) 196-12 and Section 3.2 of the Canadian Standards Association (CSA) Z662-11 Oil and Gas Pipeline Systems. Specifically, the program identifies corrosion, mechanical damage and manufacturing defects by analyzing data provided by in-line technology or by directly assessing the pipe through an excavation and physical inspection on a planned cycle. This, in turn, allows Enbridge to repair these defects before they manifest as leaks.

The capital components of the program are required to:

- Prepare pipelines to accommodate in-line inspection tools (retrofitting), and in-line inspect using intelligent tools which will identify corrosion, cracks, mechanical damage and manufacturing defects;
- complete direct assessments, where the pipeline is excavated to be physically assessed, for segments that cannot be in-line inspected; and
- repair or replace segments exhibiting corrosion, cracks, mechanical damage or manufacturing defects identified by the assessments as required by policy on a planned cycle.

The ILI runs themselves are included in the O&M budget (See Exhibit D1, Tab 17, Schedule 1).

The capital requirement shown in Table 1 below includes two prioritized pipeline retrofits per year, conducting direct assessments as required by the cyclical nature of this program (currently a seven year cycle), and remediating any potentially hazardous defects. Pipelines have been and will be prioritized using the criteria found in the Program Description below.

The capital required for the program over the forecast period is as described in the table below.

Table – 1: Capital Requirement Summary ($000)				
	Budget	Forecast		
Capital	2013	2014	2015	2016
Annual Spending	$6,861	$11,000	$8,900	$8,502

BACKGROUND

The ILI and Assessment Program for high stress pipelines started in 2001 in Ontario, with a TSSA Director's Order requiring pipeline companies to create an Integrity Management Program for pipelines operating at or over 30% SMYS. On November 1, 2012, TSSA adopted the 2011 edition of CSA Z662 Oil and Gas Pipelines Systems standard. Clause 3.2, Integrity Management of CSA Z662-11 applies to all parts of the pipeline system, whether operating above or below 30% SMYS. This clause and supporting clauses under Clauses 10.3, 10.5 and 12.10.16 require programs to be developed that effectively manage the condition and the suitability for continued safe operation of the pipeline system. Therefore, Enbridge expanded the ILI and Assessment Program to pipelines operating over 20% SMYS in 2012.

The extra high pressure (XHP – operating over 175 psi) pipelines that are part of this program are the backbone of the distribution system and also supply large industrial customers and natural gas fired power plants. As these pipelines are mostly located in urban areas, any defects that manifest as release of gas would, at a minimum, require a substantial emergency response and a temporary shutdown of the pipeline. Consequences could be more severe.

The ILI and Assessment Program for pipelines operating over 20% SMYS allows Enbridge to find and repair indications of corrosion, mechanical damage, and manufacturing defects that if left undetected could cause pipeline failures that would put public safety and gas supply reliability at risk. Between 2001 and 2011 the program focused on pipelines operating above 30% SMYS, however, starting in 2012, the Company expanded the program to include pipelines operating between 20% and 30% SMYS.

Pipelines operating between 20% and 30% SMYS have similar attributes to the pipelines operating at or above 30% SMYS that would allow ILI with some modifications, or retrofits, to the lines. Enbridge is targeting and prioritizing pipelines based on its own as well as industry experience. Prioritization parameters include land use (proximity to places of high occupancy), alternating current (AC) corrosion potential, electrical resistance weld (ERW) seam issues, pipeline coating degradation, etc.

Enbridge employs a reliability-based process, using risk analysis as a tool, for developing and prioritizing pipeline maintenance on pipeline features, such as corrosion, cracks, mechanical damage, manufacturing defects, etc. These are identified during ILI and direct assessment. Any features found are classified as requiring immediate action, scheduled for investigation, or monitored in accordance with Enbridge's policies, which have been developed based on the applicable codes, regulations, standards, and industry best practice.

Enbridge reduces the probability of pipeline failure, through its ILI and assessment process by (i) immediately remediating detected defects; (ii) in respect to less significant defects, scheduling repair on a future date; or (iii) using computer modeling to forecast when the feature should be next inspected to determine if repairs are required in future. On an annual basis, the unpredictability of the number of defects detected, particularly on lines inspected for the first time, causes the variability in the annual spending.

In 2001, a ten-year inspection plan was developed that included in-line inspections for pipelines operating at or above 30% SMYS identified in the plan. An outline of the plan was presented and accepted by the TSSA. ILIs of these lines started in 2003, and the baseline plan is scheduled to be completed by the end of 2013. The program also calls for re-inspection of these lines at a seven-year interval. Pipelines that were ILI'd early in the baseline program have started to be re-inspected, with re-inspection continuing for the remainder of the lines at a seven year frequency.

Enbridge's inspection program was expanded to include pipelines operating between 20% and 30% SMYS in 2012. In most cases, these pipelines have similar characteristics to the pipelines operating at or over 30% SMYS, such as large diameter and smooth bends that allow ILI tool passage making them good candidates for ILI.

Over time, ILI technology has evolved and become more sophisticated. Enbridge has sought to utilize newer ILI technology as it has become available, in an effort to understand the condition of its high stress pipelines in as meaningful a way as possible. Recent industry incidents such as the one in San Bruno, California, are shaping the way natural gas utilities understand and manage low probability, high consequence risks. These events are considered rare occurrences, but when triggered cause exceptional damage to people, environment and property. The San Bruno event is described more fully in Exhibit B2, Tab 2, Schedule 1. The evolution of ILI technology allows Enbridge to determine the condition of pipelines with respect to corrosion, cracks, mechanical damage and manufacturing defects to a high level of accuracy. Features that the technology identifies are mitigated based on policy, which takes into account the severity of the indication.

Left undetected, these indications could otherwise cause pipeline failures, putting public safety and gas supply reliability at risk.

The capital requirement for this program includes the modifications to the pipeline to allow the ILI operation to occur, such as straightening out bends, removing restrictive valves, and installing launching and receiving equipment for inspection tools. In addition, capital is required to complete excavation necessary to calibrate the information obtained from the inspection tools, and undertake repairs where necessary.

PROGRAM DESCRIPTION

The ILI and Assessment Program is designed to assess the condition of all operating pipelines above 20% SMYS. While it does so primarily using in-line inspection, there are other techniques such as direct inspection through excavation and external corrosion direct assessment which are also used for pipeline assessment as part of this program. With this assessment information, Enbridge determines the repair and replacement requirement for the pipelines that have been inspected. More specifically, the ILI and Assessment Program involves the following steps.

Step 1 Prioritization of Pipelines for Assessment

Enbridge will prioritize and include pipelines operating between 20% and 30% SMYS in the ILI and Assessment Program. This will result in the use of ILI and direct assessment methods to assess the integrity of prioritized steel pipelines that operate at stress levels between 20% and 30% SMYS, in addition to the original program for pipeline operating over 30% SMYS.

Enbridge will use a risk algorithm to identify those pipelines which will be prioritized for assessment using the following seven criteria:

1. External Corrosion;
2. Manufacturing Defects;
3. Welding / Fabrication Defects;
4. Equipment Failure;
5. Environmental Threats;
6. 3rd Party Damage; and,
7. Stress Corrosion Cracking (SCC)

Each of the above criteria can be associated with a consequence of failure. Targeted pipelines are ranked based on the risks identified.

Step 2 Selection of Assessment Method

Having prioritized those pipelines that require assessment, Enbridge then determines the appropriate assessment method. In situations where pipelines cannot be ILI'd, due to pipe configuration, diameter changes or fitting obstructions, alternate inspection and assessment methods can be employed. In some cases, these inspection methods do not provide as much detailed condition information as ILI assessments, and therefore may be deemed insufficient, depending on pipeline history, location and characteristics.

Step 3 Retrofitting of Pipelines

For pipelines where in-line inspection is appropriate, the next step is to modify the pipelines to accommodate ILI tools to navigate inside the pipeline. These modifications can range from the installation of tool launchers and receivers on the ends of the pipeline to be inspected, to the excavation and replacement fittings that cannot accommodate ILI tools, such as replacement of reduced port valves with new full port valves.

Step 4 Running the ILI Tools

Prior to running the ILI tool the pipe is internally cleaned to maximize the ILI tool contact with the pipe wall. The ILI tool is run through the pipeline and collects data on the pipe wall condition.

Step 5 Data Analysis

Analysis of the data collected from ILI runs or other assessment methods allows Enbridge to identify features caused by corrosion, mechanical damage degradation, dents, buckles, cracks, and manufacturing defects. Defects are categorized as Immediate, Scheduled or Monitored based on Enbridge’s policy, which follows code, regulations and best practice.

Immediate defects are those determined to have:

- predicted metal loss > 80% of nominal pipe wall thickness,
- any indication of potential failure with the pipeline operating equal to or greater than 110% of its current operating pressure,
- any dent with indicated metal loss or stress concentrator (gouges, grooves, arc burns or cracks) on the pipe surface

Scheduled defects are those determined to have:

- dents > 6% of pipe diameter
- metal loss with failure pressure less than or equal to the SMYS of the pipeline
- cracks, gouges, grooves
- probable crack indications

- metal loss greater than 50% located at welds, pipeline or other utility crossings
- areas with widespread corrosion

All features that do not meet the above criteria for defects will be Monitored defects. These identified defects will be cataloged and scheduled for re-inspection based on the applicable defect model.

Step 6 Mitigation

Temporary mitigation of Immediate defects will be within 5 days, and permanent mitigation will be completed within 60 days. Immediate defects can require a reduction in operating pressure until permanent mitigation is completed. Permanent mitigation can range from a minor repair to pipe or replacement of the pipeline segment.

Scheduled defects will be investigated and mitigated as required within a year of identification. All other defects, or Monitored defects, detected on the pipeline will be monitored and remediate before they become hazardous.

Forecasted Capital Costs

The costs shown in Table 3 below include labour and material associated with retrofitting two pipelines per year and integrity excavations to mitigate defects identified. This includes the purchase of several re-useable ILI tool launchers and receivers in 2013. This is one of the reasons for the variance between the 2013 budget and the 2014 forecast shown in the remediation, mitigation and equipment line. Another reason for this variance is the completion of the balance of the assessments of the 30 % SMYS pipelines in 2013 under the 10 year plan. Retrofits costs are one-time costs. The cost of running the ILI tools and the execution of other assessment methods are O&M expenditures.

Table 3: Capital Requirements for ILI				
	Budget	Forecast		
Activity ($000)	2013	2014	2015	2016
Excavations, Remediation, and Equipment	6,861	4,500	2,350	2,000
Retrofit Pipelines to ILI	15	6,600	6,550	6,502
Total	6,876	11,000	8,900	8,502

The 2014 to 2016 forecast costs for Excavations, Remediation, and Equipment are based on a bottom up approach beginning with the number of excavations that are anticipated. This estimate is informed by the age and condition of a specific pipeline. The estimate of the number of excavations that will be required and the costs of each is a function of the Company's past experience.

Enbridge has identified six targeted Lines for inspection from 2014 to 2016. Capital required to retrofit these lines is itemized in Table – 4.

Table 4 - Retrofit Capital Costs of Targeted Pipeline ($000)			
Targeted Pipeline	2014	2015	2016
NPS 24 Metrowest Ph1	3,700		
NPS 24 Metrowest Ph2	2,900		
NPS 12 White and Forks		2,078	
NPS 12 St Laurent Control District		4,472	
NPS 30 Lisgar-Albion-Keele (Phase 1)[1]			3,201
NPS 12 Rideau Heights			3,301
Total	6,600	6,550	6,502

Note: 1. This project will require multiple phases over at least two years.

The estimated costs for the above targeted pipeline projects are also developed using a bottom up approach which is informed by the length and diameter of the pipeline, the number of fittings and the location and complexity of the area where the launcher and receiver are to be installed.

RIGHT-OF-WAY RISK MITIGATION

Summary

Technological innovations enable Enbridge to enhance the safe and reliable supply of natural gas to its customers. These innovations are applied to existing processes and allow Enbridge to mitigate and eliminate risk and improve system operation. Technological innovations increase the efficiency and productivity of existing programs. Enbridge maintains a prudent approach to capital spending by using North American consortiums to leverage investments for research, development, and implementation of new technology. Through the Right-of-Way Risk Mitigation program, Enbridge will use technological innovations to reduce the risk of pipeline strikes on critical pipelines in public right-of-ways.

The implementation of the proposed program includes a fiber optic ground disturbance notification system, a ground sensor system, and video analytics software. These systems provide a prudent opportunity to enhance current damage prevention programs by leveraging emerging technologies to increase the monitoring frequency and overall protection of Enbridge pipelines. This will reduce the likelihood of pipeline strikes and the consequences of a pipeline leak or rupture. Table 1 outlines the proposed capital requirements for this program.

Table 1: Capital Requirements Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Right-of-Way Risk Mitigation		581	935	1,770

Background

Critical natural gas distribution pipelines are installed in road allowances, public right-of-ways, utility corridors, and green spaces in order to allow for ease of installation and broad distribution throughout the Enbridge network. The critical pipelines referred to in this program include those installed in utility corridors and green spaces. These critical pipelines are made of steel, are as large as 36 inches in diameter, and operate at up to 650 psi. In order to protect these pipelines from damages, including pipeline strikes resulting from excavation and horizontal directional drilling, Enbridge currently employs a damage prevention program.

The current damage prevention program mitigates the risk of pipeline strikes in right-of-ways through the following:

- Visual inspections either on foot, by vehicle or through aerial surveillance flights
- Acoustic pipe monitoring through a system that detects vibrations resulting from line hits, a new technology incorporated on one vital line
- Public awareness
- Pipeline identification through line markers
- Pipeline locates and supporting legislated participation

Pipeline strikes account for a significant number of incidents occurring on pipelines. These strikes have a direct impact on the safety of workers and the public and the reliability of the Enbridge distribution system to its customers.

In order to gain exposure to technological advances, Enbridge partners with various collaborative innovation groups that develop technology and allow member organizations to leverage funding. These groups include North American consortiums involving other utilities and Government bodies. Partnering with these collaborative innovation groups, such as NYSearch and the Operations Technology Development (OTD) of the Gas Technology Institute (GTI) allows Enbridge to adopt a prudent approach to spending by leveraging its resources with those of other member organizations. This partnership also allows Enbridge to gain insight into innovations and ensure that the solutions can be effectively applied to specific Enbridge objectives. Decision matrices and vendor comparison guide how Enbridge chooses technological innovations for implementation.

All the technologies that are being proposed in this program have been assessed based on Enbridge's criteria. These technologies have undergone assessment, testing and evaluation through third parties, such as OTD and NYSearch.

Program Description

In order to enhance Enbridge's existing damage prevention program, objectives were established to enhance the frequency and effectiveness of the technology employed to protect pipelines installed in utility corridors and green spaces. These objectives included the ability to constantly monitor for potential threats in a cost effective, reliable manner. In addition, existing site limitations and operational factors were taken into consideration.

An assessment of various possible technologies has resulted in the proposed Right-of-Way Risk Mitigation program. It will have three components, including:

- Fiber Optic System –Optical fibers are buried above or nearby the pipeline to detect potential impending pipeline strikes. A single system can protect up to 50 km of pipeline, with multiple systems networked together for longer distances. A laser beam is transmitted along the buried fiber optic cable and the returned signal is continuously monitored. When construction equipment is near the pipeline, the ground above the fiber is compressed and vibrated. This changes the optical properties of the fiber and the change in returned signal is identified and analyzed by the sensing controller. The returned signal is processed to minimize false alarms, while maintaining an acceptable level of threat detection. The controller would then notify Enbridge personnel about the potential risk of a pipeline strike. Enbridge proposes to install 3 km in 2014, 5 km in 2015, and 10 km in 2016. This will allow Enbridge to refine its installation and operation procedures and increase the effectiveness of the program as it progresses.

- Embedded Sensor Technology – Embedded sensors are designed to detect digging and other potentially hazardous activities in close proximity to buried pipelines. This technology is deployed in the field through the periodic placement of sensing cells along the pipeline easement. These sensors detect activities in the pipeline installation location. The system can then analyze these activities, define them as threats, raise an alarm, and then notify the appropriate response areas or personnel for proper reaction. This is intended to occur before a strike occurs. Embedded sensor systems convert vibration produced by surface and sub-surface activity into electrical impulses. Signal processing electronics are employed to analyze the electrical signal for indications of digging or drilling. Enbridge proposes to install 3 km in 2014, 5 km in 2015, and 10 km in 2016 at different locations than the fiber optic installations based on site requirements. This will allow Enbridge to refine its installation and operation procedures and increase the effectiveness of the program as it progresses. This technology provides protection for unique situations that are better situated for circular protection areas, for example branched connections.

- Video Analytics – Advanced software is combined with video camera technology to generate an alarm when there is potentially hazardous activity near a pipeline while ignoring all other activity around the pipeline installation area. This system allows for unattended monitoring of pipelines in both remote and urban areas. It also allows operators to respond to digging events by being alerted that they are taking place. The e-mail alert includes a series of pictures that can assist in determining the criticality of the alarm notification. Enbridge proposes to install 2 sites in 2014 and 2 sites in 2015. This will allow Enbridge to refine its installation and operation procedures and determine optimal site characteristics to increase the effectiveness of the program as it progresses.

Capital Requirements

Table 2 shows a breakdown of capital requirements for the Right-of-Way Risk Mitigation Program.

Table 2: Capital Requirements Breakdown ($000)							
DESCRIPTION	Unit Cost	Forecast					
		2014		2015		2016	
		Qty	Total	Qty	Total	Qty	Total
Fiber Optic System (per km)	107	3	321	5	535	10	1,070
Embedded Sensor System (per km)	70	3	210	5	350	10	700
Video Analytics (per system)	25	2	50	2	50	0	0
		TOTAL	581		935		1,770

MAINS REPLACEMENT PROJECTS UNDER $ 2 MILLION OVER THE FORECAST PERIOD (2014 -2016)

Table 1: Mains Replacement – Projects Under $ 2 million			
Description	Forecast ($000)		
	2014	2015	2016
AC Corrosion (Remediation work)	102	52	27
Acoustic Pipe Locator	64	64	64
Advanced Metering Infrastructure (net of adjustment)	131	175	69
Cathodic Disbondment Detector	20	100	-
Coated Steel Program (Mains & Services)	362	-	-
CP Monitor	35	35	35
Cross Bores - Mechanical Spring	20	-	125
Emergency Containment System	60	-	-
Encased Bridge Crossings Study	-	208	0
Enhanced Leak Survey Technology	100	-	-
Isolated Steel Mains CP Program	82	-	-
Metallic Joint Locator	40	-	-
Mobile By-Pass System	140	-	-
N-1 (reliability of supply for Single source networks)	-	520	0
Odorant Fade	150	225	-
Pipeline Markers	10	10	11
Remote Leak Survey Using Laser	150	300	-
Ridgid Crosschek - Cross bores detection system	100	100	-
Tool for Underground Power Line Detection	6	-	-
Total	1,572	1,790	331

CAPITAL REQUIREMENTS – SERVICE REPLACEMENT

Summary

1. Service replacement programs and projects are ongoing activities that include replacing combinations of the existing service lines (small diameter pipelines from the mains to the customers meter), the service line connections at the main, and the service riser which provides a transition from the below ground service line to the meter and regulator above ground. These gas distribution network components periodically need replacement for a number of reasons. These include service lines, main connections and risers that are either at or near the end of their useful life, or are being replaced to address integrity and reliability risks. This evidence also includes associated programs needed to assess and enhance the integrity or reliability of the service lines.

2. The Service Replacement capital requirement for the period of 2013–2016 is summarized in Table 1. See Table 2 for detailed breakdown of programs included.

Table 1: Capital Requirements ($000s)

Description	Budget	Forecast		
	2013	2014	2015	2016
Service Replacement	17,814	21,118	25,011	41,216

3. The following programs and projects are detailed in evidence:
    a. Miscellaneous Service Replacements or Relays

Witnesses: D. Lapp
L. Lawler

b. AMP Fitting Replacement Program
c. Compression Outlet Service Tee (COST) Replacement Program
d. Sewer Safety Program
e. Service Replacement Projects Under $ 2 million

4. The Miscellaneous Service Replacements or Relays capital requirement is based on the general need to replace services that are identified within the forecast year. These Relay requirements are as a result of the ongoing leak and corrosion monitoring and response programs, general maintenance activities, damages from third parties or as a result of customer requests (for added load or for altering the location of their service). This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 3, Attachment 1.

5. The objective of the AMP Fitting Replacement Program is to reduce the risk associated with the increasing incidents of failure of the copper piping downstream of these AMP fittings. An AMP fitting is a mechanical fitting installed between 1969 and 1984, on below ground residential gas service lines. This fitting provides a transition from the plastic service line to a copper riser. Approximately 320,000 AMP Fittings have been installed across the Enbridge system. This program involves the replacement of the AMP Fittings and copper risers in parallel with increased leak survey monitoring on all services with AMP Fittings. The main objective is to replace the AMP fittings and risers before the riser starts to leak. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 3, Attachment 2.

6. The COST Program will replace target fittings together and service lines. Approximately 110,000 Compression Outlet Service Tees were installed in Enbridge's system from the late 1950's to the 1980's. These fittings were utilized to

connect steel services to steel mains without the need for welding. These fittings can pull apart or lose their seal with excavations in close proximity or with localized ground movement. Based on a study initiated in 2012, Enbridge implemented a long term targeted replacement program that will proactively prevent leaks and resulting incidents. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 3, Attachment 3.

7. In 2010 Enbridge initiated a Sewer Safety Program (the "SSP") in order to prudently manage and mitigate the safety risks specific to sewer laterals and to prevent the inadvertent intersection of a natural gas pipeline with a sewer lateral (a crossbore). Since that time, Enbridge has continued with the SSP and has now incorporated the activities begun in the SSP into its daily construction practices. This evidence is consistent with the description of the SSP submitted to the Board and reviewed in EB-2011-0277 and subsequently mandated under provincial law via the TSSA Oil & Gas Pipeline Systems Code Adoption Document (FS-196-12). This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 3, Attachment 4.

8. Other service replacement projects with a total capital requirement below $ 2 million over the forecast period are summarized at Exhibit B2, Tab 5, Schedule 3, Attachment 5.

9. Table 2 summarizes all of the direct capital requirements for the programs and projects associated with the replacement of services within the Company's distribution network.

Witnesses: D. Lapp
L. Lawler

Table 2: Service Replacement Capital Requirements ($000s)

Description	Budget	Forecast Period		
	2013	2014	2015	2016
Misc. Service Replacements (Relays)	7,200	6,063	6,401	5,381
AMP Fitting Replacement Program	4,000	8,543	13,100	30,046
Compression Outlet Service Tee Replacement Program	1,029	2,866	2,924	2,982
Sewer Safety Program	1,839	1,530	1,561	1,592
Service Replacement Projects Under $ 2 million	3,775	2,117	1,025	1,215
Total	17,843	21,118	25,011	41,216

Witnesses: D. Lapp
L. Lawler

MISCELLANEOUS SERVICE LINE REPLACEMENTS (RELAYS)

This evidence is intended to provide information about Enbridge's activities related to the replacement of service lines that are identified within any given year. These service pipeline replacements are generally referred to as a service relay or simply, relays. The majority of the service line replacements are identified during the course of day to day operations and result from actives such as maintenance work, third party damages and responding to leaks or corrosion faults.

The capital cost associated with service line relays for the forecast period, 2014 to 2016, is $17.8 million.

Background

General Service Relays

General service replacements or relays are unplanned (specific locations unknown) and carried out as a result of the leak and corrosion monitoring and response processes, maintenance activities, third party damages or as a result of requests from customers. Enbridge requires that lines constructed of a specific material type or of a particular age cannot be repaired or reused. Timely and complete replacement is necessary to ensure operational safety and reliability, as well as to maintain service to our customers. If a service line is an isolated steel pipeline with inadequate cathodic protection then generally these service line will be replaced rather than installing new or incremental cathodc protection.

Customers also request replacement services to accommodate the need to relocate an existing service or to address the need for increase delivery capacity.

The projected number of service line replacements in this category is arrived at using historical data trends. Typically, the Company will replace approximately 1500 services per year with this number vary based on the external drivers noted above.

Capital Requirements

The table below identifies the forecast spend for this program from 2014 through 2016. These costs include all labour, material, and restoration.

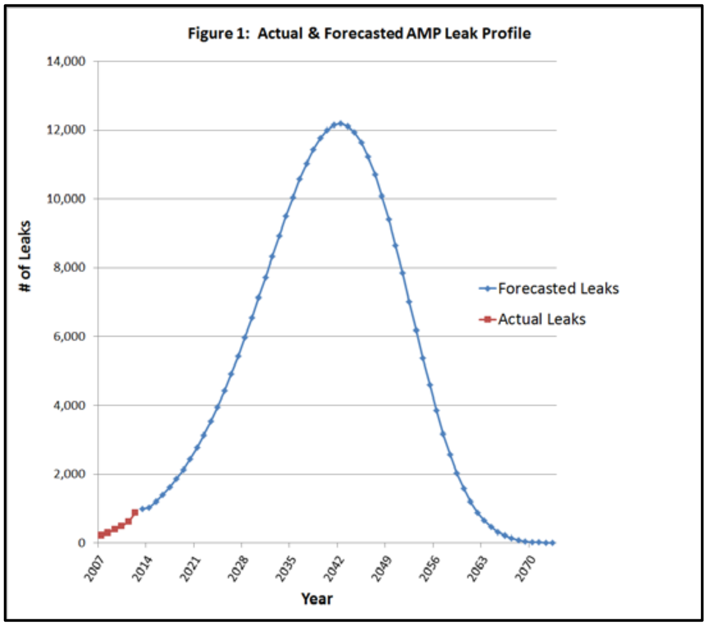
Table 1: Miscellaneous Service Replacements (Relays) ($000)				
Description	Budget	Forecast		
	2013	2014	2015	2016
Misc. Service Replacements	7,200	6,063	6,401	5,381

AMP FITTING REPLACEMENT PROGRAM

Summary

The objective of the AMP Fitting Replacement Program is to reduce the risk associated with the increasing failures of the copper piping downstream of these AMP fittings. An AMP fitting is a mechanical fitting (see Figure 2 which shows a typical AMP fitting), installed between 1969 and 1984, on below ground residential gas service lines, in order to transition from a plastic service line to a copper riser. Approximately 320,000 AMP Fittings have been installed across the Enbridge system. The program involves the replacement of the AMP Fittings and copper riser together with increased leak survey monitoring on all services with AMP Fittings. The main objective is to replace the AMP fittings and risers before the riser starts to leak.

Over the past six years, Enbridge has experienced an increased rate of leaks on AMP fittings over its historical rates. Between 2007 and 2012, detected and reported leaks related to AMP fittings have been identified as increasing at the rate of approximately 30% per year. In 2011, 608 leaks were reported related to AMP fittings. Due to the increase seen in the leak rates, Enbridge commenced a targeted leak survey program for AMP fittings in 2012, which found 880 or 172 more than the previous year. In the same year Enbridge also commenced a 2 studies to examine a sampling of AMP fittings to determine the condition of these assets, the mechanism of the failure, the projected life expectancy and the optimal response. The conclusion of these studies is that AMP related leaks are likely to continue to increase at an accelerated rate, roughly doubling from the 2012 number over the next five years and increasing four to six fold within the next 12-14 years. Specifically the leak forecast developed by Banak Inc generates the following leak rate profile (See Figure 1). Based on this study Enbridge recognized that this leak rate is not acceptable and requires an appropriate response. The AMP Fitting Replacement Program is that response.



This program commenced in 2012/13 (leak surveys and replacements) and continues. Enbridge has increased its leak survey monitoring and over the next three years will leak survey 100% of the services with AMP fittings annually. Leaks associated with AMP fittings are below ground leaks and are addressed under the current emergency response protocol. Enbridge determined that the replacement over time of all AMP fittings based on risk and operational capacity best ensures continued compliance with the safe and reliable delivery of gas.

The total forecasted three year capital requirement to implement the program for the years 2014 to 2016 is $43.7 million as listed in Table 1.

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
Year	**2013**	**2014**	**2015**	**2016**
Spend	$4,000	$8,543	$13,100	$30,046
Units	2,000	4,000	6,000	13,600
Unit Cost ($)	$2,000	$2,135	$2,183	$2,209

Background

Two basic characteristics of natural gas are that it is lighter than air and when it is released from containment, it will follow the path of least resistance. In most cases, a release of gas will result in the gas escaping to the atmosphere with minor consequences. However if the release of gas follows a path of least resistance into a confined space (eg. customer's home), increasing the probability of ignition, serious consequences can result.

Enbridge has experienced an increase in the leak rate related to these fittings over the past years. This increased leak rate associated with this configuration is of concern. The leaks associated with the copper riser can vary from a pinhole leak to a full circumferential crack and failure, depending on the influencing factors such as external loading and/or impingement. Impingement occurs when rocks and hard materials in the trench are in direct contact with the copper riser and can potentially cause localized damage. The fitting and the riser are in the majority of cases in direct proximity to customer home or building (seen in Figure 3). In a worst case scenario, these leaks have the potential to enter customer's homes or building, particularly in the winter months, when the ground is frozen and the leaking gas is less able to vent to atmosphere. Contributing to this risk is the freeze/thaw cycle which fatigues the already corroded copper riser. Under these circumstances there is a possibility that the migrating natural gas can accumulate inside the customer's home or building. The accumulation of natural gas in an enclosed space could create a hazardous situation should it reach the lower explosive limit (approximately 4% gas-in-air).

Figure 2: Typical AMP fitting

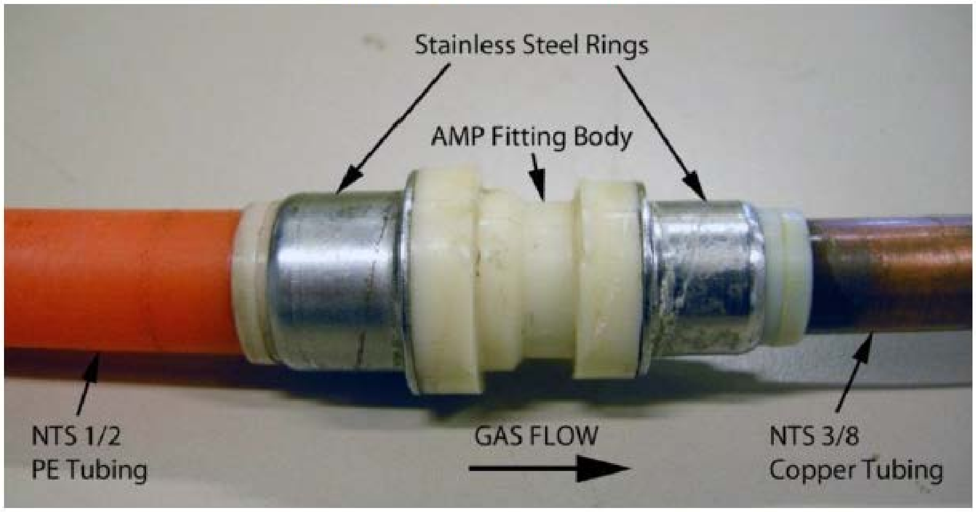
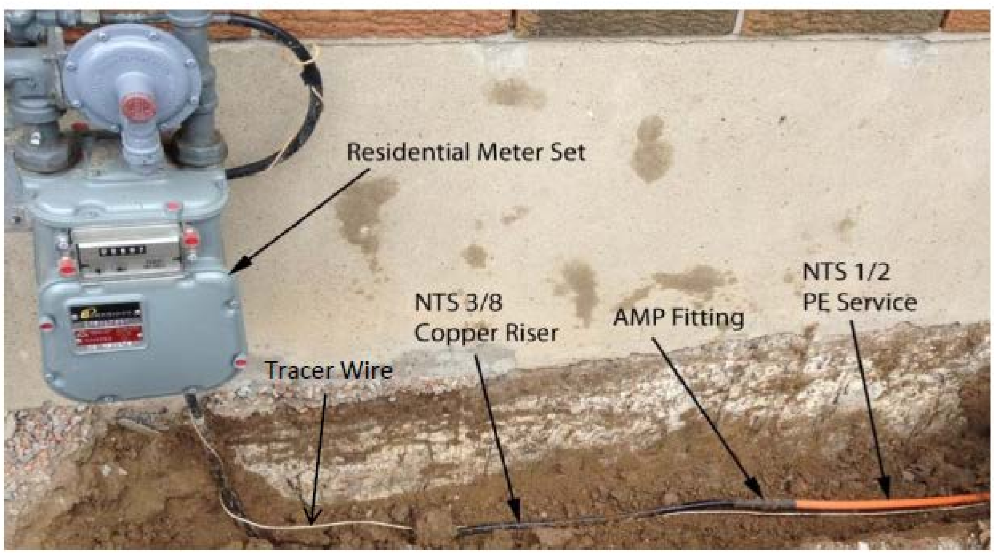
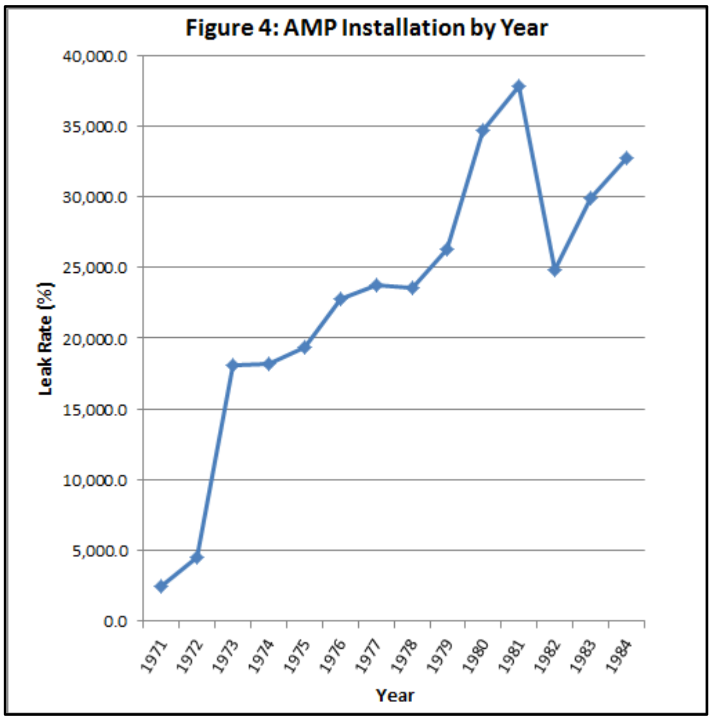


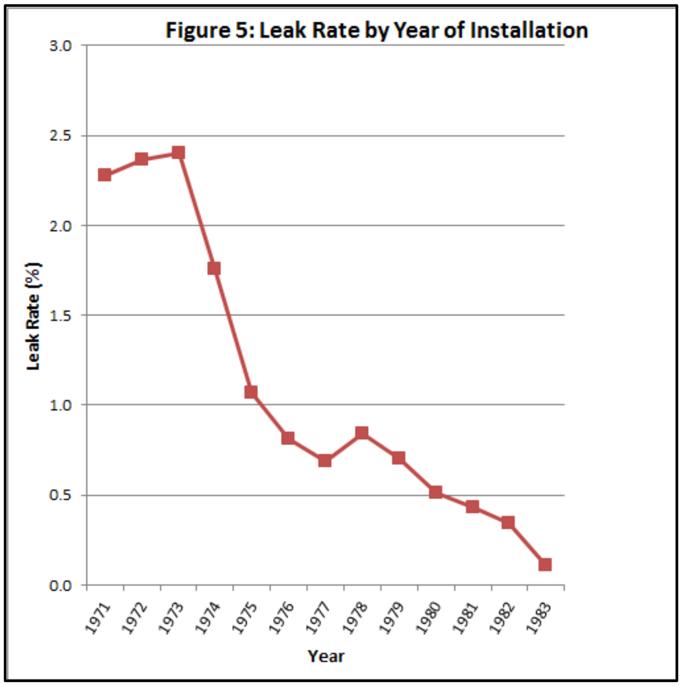
Figure 3: Typical AMP fitting installation



In Figure 4 below, Enbridge sets out the profile of the installation of the AMP fittings and copper risers over the relevant period. As can be seen from Figure 4, the pace of installations increased significantly after 1973. From the period that these fittings and risers were installed the total remaining in service are approximately 320,000.



As can be seen in Figure 5 below, the actual rate, as detected by the Company, of the AMP fitting related leaks is highest in respect to the oldest installations (data collected from 2007 to 2012). The leak rate for these older AMP fittings is approximately 2.3 %. In 2012, a total of 880 leaks related to AMP fittings were detected which represented 47% of the Company's total below ground leaks for that year. Based on the studies that Enbridge commissioned (as discussed below), the expectation is that this leak rate will accelerate and include more recent installations.



In 2012, approximately 59% of AMP leaks were detected by the Company's leak survey program with the remaining 41% of AMP leaks being identified outside the program (called in by the public or found by service technicians or other gas company representatives). Enbridge has undertaken incremental leak surveys to date which were limited in scope targeting the older installations of AMP fittings and copper risers. In future the Company will be undertaking annual surveys of all remaining AMP fitting and copper riser installations.

<u>AMP Fitting Studies 2012</u>

In response to the increased number of leak incidents associated with these fittings, Enbridge commissioned two studies in 2012 to understand the:

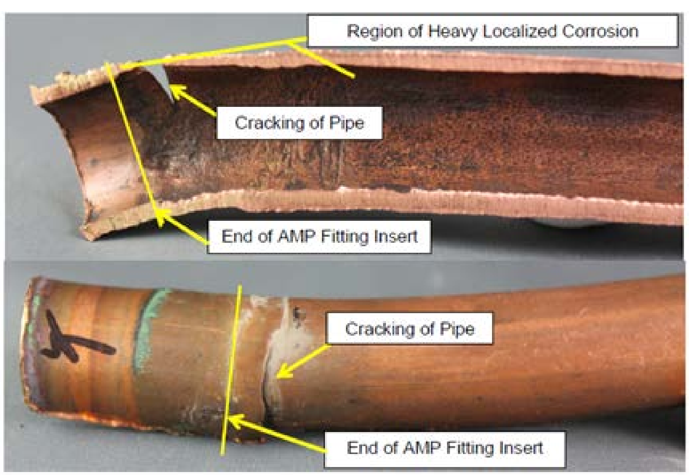
- condition,
- failure mechanism and,
- expected frequency of leaks, and

- optimal response to the problem.

One study, performed by Jana Laboratories Inc., consulting engineers with expertise in defect failure analysis of pipelines, determined, following the analysis of a broadly representative sample of 700 exhumed AMP fittings, that all of these fittings demonstrated corrosion. This contributed to Jana's opinion that the amp fitting system is failing at an accelerating pace. Indeed, on page 2 of the Jana report, it was reported that leak rates are projected to increase at an accelerating rate, increasing by four to six fold in the next 10 years.

Jana concluded that the mechanism of failure, or leak, is associated with corrosion of the copper riser downstream of the fitting (See Figure 6).

Figure 6: Copper Failure due to localized Corrosion



The failure mechanism has been determined to be impacted by the age of the fitting and risers and the gas flow rate through the assembly. The corrosion is a result of trace and expected levels of hydrogen sulphide (H_2S) in the natural gas and is associated with flow turbulence at the AMP Fitting outlet. The primary variables impacting the minimum remaining life of the copper riser are its age (wall loss increases with age), flow rate (wall loss increases with flow rate), and imperfections in the copper downstream of the fitting. Such imperfections increase turbulence and therefore accelerate wall loss. Higher flow rates (consistent with customers with higher gas consumption rates) effectively accelerate the corrosion through a combined erosion and corrosion mechanism. The flow rate is a significant contributor in that it accelerates the corrosion mechanism by causing scouring of the riser's copper wall as the gas flows through the it (analogous to the erosion mechanism of a river on a river bank due to turbulent flow).

Conclusion

The AMP fittings and copper risers leak rates are unacceptable and the situation is likely to worsen over time.

A targeted remediation program is therefore recommended to stabilize and manage the forecasted accelerating increase in risk associated with the increase in leak rates. In order to achieve the greatest optimization, the remediation program will involve implementation of a long term AMP fittings replacement program and annual leak monitoring of the entire AMP Fitting population (ramped up starting in 2012 and over the next three years). To the extent possible, Enbridge will look for efficiencies in managing the replacement of these fittings through synergies with other asset replacement programs as warranted. On an annual basis, the AMP fitting program will be re-evaluated to measure how the leaks track with the forecasted leak rate, and the program pace will be re-evaluated based on the data.

Program Description

A replacement optimization has been developed for the AMP Program that takes into consideration the following:

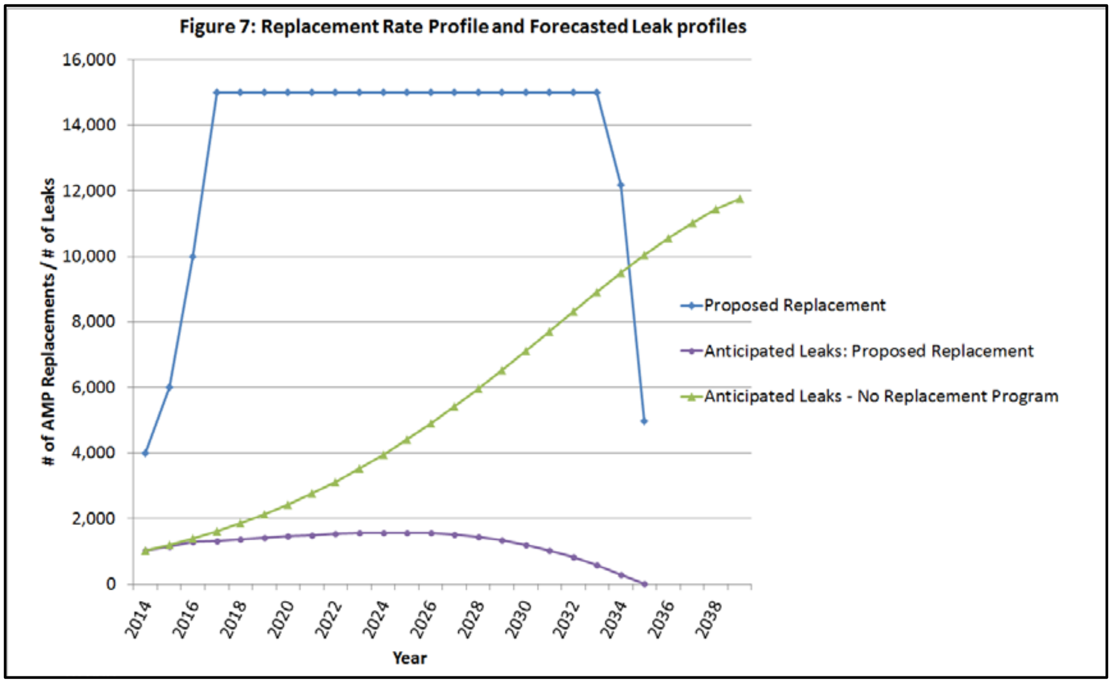
- level of risk associated with the number of leaks required to be managed,
- capacity for emergency response early in the program,

- capacity to perform the replacement program early in the program, and
- program cost.

The program design utilized the results of the Jana AMP study and the second study completed in 2013 by BANAK Inc., *Program Optimization Approach*, to determine the optimal program. This program considers the proactive replacement of AMP fittings and copper risers in combination with replacements that are triggered by a detected leak.

Today, the replacement profile shown in Figure 7 has been identified as the optimal replacement profile for 2013 to 2016. This profile will be evaluated on an ongoing basis so that Enbridge can remain ahead of the failure curve in an optimized way, to the extent practical.

The Figure 7 below identifies program replacement impact on the leak rates. The green curve represents the leak profile that is anticipated if the AMP fitting replacement program is not undertaken. The “Anticipated Leaks: Proposed Replacements” represented by the purple curve, shows the anticipated number of annual leaks that will occur during the replacement program period. The program “Proposed Replacements” represented by the blue curve show the planned rate of annual replacement which will be completed under the program. Over the forecast period this replacement rate will increase from 4,000 replacements in 2014 to 10,000 in 2016.



The Company intends to reevaluate the program as needed, which may mean accelerating or decelerating, in response to the actual leak rate experienced. The Company did evaluate alternative replacement rates over time and concluded that any material decrease in the annual replacement rate led to an unacceptable increase in the annual anticipated leak rate.

Capital Requirements

The total forecasted three year capital cost to implement the replacement program for the years 2014 to 2016 is $43.7 million as listed in Table 2. These costs include the material, labour and restoration costs needed to replace the AMP and copper riser as defined above.

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
Year	**2013**	**2014**	**2015**	**2016**
Spend	$4,000	$8,543	$13,100	$30,046
Units	2,000	4,000	6,000	13,600
Unit Cost ($)	$2,000	$2,135	$2,183	$2,209

COMPRESSION OUTLET SERVICE TEES

Summary

Compression Outlet Service Tee's (COST) were installed in Enbridge's Gas Distribution system in the late 1950's to the 1980's. These fittings were utilized to connect steel services off steel mains without the need for a welded outlet connection. Their lack of resistance against longitudinal pullout forces or thrust forces (i.e. the forces attempting to pull a pipe out of the fitting) make these components vulnerable to ground movement and third party damages which can result in a loss of containment of gas. Over the years Enbridge has experienced leaking fittings, and a number of occurrences where total pull out had occurred.

To mitigate the risks of compression outlet service tee failures a program consisting of three primary elements has been implemented. These elements are:

1. Awareness – by uploading all COST population to the Geographical Information System (GIS) and informing all Enbridge employees, contractors etc. about the risk associated working near these locations;
2. Proactive replacement program - based on planned works associated with these locations by Enbridge or any other third party.
3. Conducting targeted leak surveys to mitigate the risk associated with the failure of these fittings due to excavation and frost heave.

This program optimizes the capital outlay and targets the assets that are potentially subject to the conditions causing failure. This approach balances risk and cost and the implementation can be done in an efficient manner by being linked to work that will be undertaken by Enbridge or third parties. With this program in place the risk of an incident from the failure of a COST will be significantly reduced.

The capital requirements for the program over the forecasted period are shown in Table 1 below:

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
Description	2013	2014	2015	2016
Program Cost	1,029	2,866	2,924	2,982

Background

A compression outlet service tee (COST) is a fitting used to connect steel services off steel mains without the need for a welded outlet connection (see Figures 1 and 2 for an illustration of these fittings). Their lack of resistance against longitudinal pullout forces or thrust forces make these components vulnerable to ground movement and third party damages which can result in a loss of containment of gas. Approximately 110,000 COST Fittings were installed in the Enbridge system from the late 1950's to the 1980's. Enbridge has experienced a number of occurrences where total pull out has occurred, leading to loss of containment.


Figure 1: Compression Outlet Service Tee installed   Figure 2: Compression Outlet Service Tee

Enbridge identified the need for a study of this component from the Asset Plan process conducted in 2011. As a result, Enbridge commenced a study in 2012 to understand the condition and failure modes of the COSTs and to determine if an incremental mitigation program is required.

The study involved:

- defining the COST population and confirming the locations of these fittings,
- testing a representative sample of the COST population to learn about the condition of the fitting, and the integrity of service connection,
- understanding the failure mechanism and
- planning the risk mitigation to address the risks associated with this fitting.

Preliminary test results show that the fitting does not leak unless there is a longitudinal pullout force or thrust force. This force could be caused by third party excavation or ground movement caused by frost heaving. Over 50% of the fittings studied presented with some degree of pull-out. For this reason, Enbridge identified a need to be more proactive in reducing the risk associated with these fittings on a risk prioritized basis.

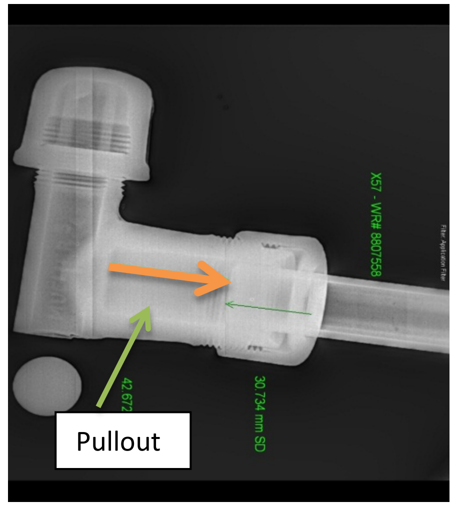


Figure 3: Exposed COST with Pullout

Figure 4: X-ray of Pullout

Figure 3 illustrates a COST fitting exposed with pulled service pipe. The pullout portion can be seen by the change in diameter of the pipe nearest the fitting outlet. The expectation of a proper installation is that the service pipe butts up to the inside surface of the COST, such that there is no gap. It can be seen from the x-ray in Figure 4 that some force has pulled the pipes apart within the fitting. As this gap increases, the likelihood of a full service pull out also increases. Furthermore, it is believed that continual freeze/thaw cycles can potentially exacerbate these already vulnerable fittings and cause them to pull out entirely. This kind of situation can lead to loss of containment, and a potential safety hazard. The nature of this type of failure can lead to catastrophic consequences because the leak created when the service pulls out of the tee can be underground. Rather than natural gas escaping to atmosphere, as happens with most damages, the natural gas will follow the path of least resistance, which may be underground and into a building, where a source of ignition may exist.

Enbridge and third party excavators perform work every year in the vicinity of these vulnerable fittings. Heavy works performed over these fittings associated with large excavation equipment as well as compaction activities impair the integrity of the compression connection of these fittings to the service.

Description of Work

The COST program is a proactive approach to eliminating a known risk on the distribution system. The program will confirm the location of these fittings, document these in GIS, and mitigate services at risk associated with municipal work.

This will involve the implementation of a long term targeted COST replacement program. The COST program requirements were established based on the preliminary results of the 2012 COST study and will be further refined as the study is finalized. The tasks will include the following remediation:

- Identify the COST population data in Geographical Information System (GIS)
- Inform all Enbridge employees, contractors etc. about the risk associated working near these locations
- Examine records for COST fittings prior to any excavation work in the area of ENBRIDGE system.
- Replace vintage steel services where COST Fittings are installed and impacted by any work.
- Increase leak survey inspections for targeted COST fitting population to mitigate the risk associated with the failure of these fittings due to excavation and frost heave.

The main purpose of this program is to remove these COST connections in a controlled manner before conducting any other works nearby which can lead to interference with the fitting, pipe pullout, leaks and even a severe incident.

The following alternatives were considered before selecting the preferred alternative:

1. Condition monitoring program and repair when leaking,
2. Complete replacement of all existing COSTs,
3. Condition based replacement.

Alternative 1

This alternative maintains the current practice of condition monitoring and repair when leaking. This approach where steel mains are leak surveyed on a certain frequency, and when leaks are detected, or called in by the public, they are repaired. This alternative was rejected because it does not improve the safety and reliability of the distribution system. A proactive approach would be the only prudent mitigation.

Alternative 2

This alternative involves the complete replacement of all existing COSTs through a replacement program. The replacement would be prioritized based on Enbridge or third party works, pressure class, vintage of fittings, area or failure trends identified. A full replacement program would cost approximately $275 million. Full replacement of these components can provide improvement to the safety and reliably of the system and can reduce or potentially eliminate the associated risks that these components have on the system. However a full replacement program would result in unnecessary work and disruption to customers caused by replacing fittings that are neither in the vulnerable locations nor posing any risks to system safety. For this reason this alternative was rejected.

Alternative 3

This alternative involves the use of a risk-based approach to replacement. XHP instances of COST will be proactively excavated and removed. Because of the mode of failure of these fittings, the greatest risk is primarily due to municipal and other works in an area with COST fittings. Removal and replacement of COST prior to other works by Enbridge or third parties such as municipal work will reduce the associated risk. This assumption is based on the COST study preliminary results. The COST will be identified when Enbridge receives construction plans from municipalities, and determines whether the proposed work will impact the gas mains. This option targets the COST fitting locations that are at increased risk due to the planned works and these only will be removed, and therefore optimizes capital requirements.

The preferred alternative is Alternative 3. This alternative optimizes the capital outlay and targets the assets that are potentially subject to the conditions causing failure and limits unnecessary disruptions to customers, while providing improvement to safety and reliability.

Required Capital Costs

The COST program is an on-going replacement program extending over the next 20 years. Table 2 below identifies the capital requirement for the program over the forecast period.

Table 2: Capital Cost Summary ($000)

	Budget	Forecast		
Description	2013	2014	2015	2016
Program Cost	1,029	2,866	2,924	2,982
Units	294	820	820	820

SEWER SAFETY PROGRAM

Summary

In 2010 Enbridge initiated a Sewer Safety Program (the "SSP") in order to prudently manage and mitigate the safety risks specific to sewer laterals and to prevent the inadvertent intersection of a natural gas pipeline with a sewer lateral (a crossbore). Since that time, Enbridge has continued with the SSP and has now incorporated the activities begun in the SSP into its daily construction practices. The pre-filed evidence submitted as part of this application is consistent with the description of the SSP submitted to the Board and reviewed in EB-2011-0277 and subsequently mandated under provincial law via the TSSA Oil & Gas Pipeline Systems Code Adoption Document (FS-196-12). In the EB-2011-0277 Decision and Order dated May 10, 2012, the Board found that the SSP is an activity that a prudent utility would undertake (page 13 of the Decision). The capital costs submitted for 2014 to 2016, incorporate the SSP activities as Enbridge continues its efforts to protect customer and public safety consistent with the TSSA code adoption requirements.

The capital components of the SSP are forecasted in Table 1 below.

Table 1: Capital Cost Summary ($000)

	Budget	Forecast		
Description	2013	2014	2015	2016
Construction & excavation for trenchless installations	1,769	1,445	1,496	1,532
Relocations & relays to address legacy crossbores	50	50	50	50
Development & implementation of a new records management and tracking process	20	35	15	10
TOTAL	1,839	1,530	1,561	1,592

The capital components of the SSP are comprised of the following activities:

a) Mitigation of the potential interaction of natural gas lines with sewer lines by requesting private sewer lateral locates, completing site assessments and visual verification prior to the installation of new natural gas pipelines and constructing sewer lateral specific transition holes and excavations to expose the pipeline.
b) Relocations & relays to address legacy crossbores.
c) Implementation of a process that geo-spatially identifies and tracks field information for sewer lateral locations.

Background

Trenchless technologies have been utilized as the preferred method of installing utilities since the 1970's. This construction technique saves time and money, minimizes traffic disruption, and results in less damage to property, roadways, water courses and tree roots during pipeline installation. Trenchless technologies are often used in established neighborhoods and urban areas where the open trench method would be expensive and intrusive. A horizontal directional drill and a torpedo are examples of trenchless equipment used in this construction technique.

Trenchless technology, does however, increase the potential for the inadvertent intersection between gas and a sewer line (a crossbore). Figure 1 shows a crossbore where the gas is intersecting a sewer lateral. The crossbore becomes a problem when the sewer becomes blocked, and the customer, their contractor or the municipality cleans out the sewer line with rotary cutting and/or water jetting equipment. This equipment is extended down through the sewer line and rotates to cut through any obstruction that is blocking the sewer line including the natural gas pipeline that has penetrated the sewer.

When blockages beyond the outside wall of a building are cleared using this equipment, natural gas lines can be damaged. If there is a gas pipeline intersecting the sewer, the rotating equipment can drill through the gas line. This damage can result in a natural gas escape into homes and buildings and can create a safety issue. Because the sewer acts as a direct path for escaping gas into the customer's home, there is potential for ignition and/or an explosion. A cutting attachment is one of the implements that can be used on the end of rotating equipment used to clear sewer lines.

Figure 1: Rendering of a crossbore

In May 2004, an Ogdensburg, New York home was destroyed after a city crew operating power auger equipment in the domestic sewer line at a home inadvertently cut into a ½" plastic natural gas line. Tragically, one person was fatally injured and others sustained serious non-fatal injuries.

In the case of the Ogdensburg, New York incident, the explosion could have been prevented had the cross bore not occurred. Figure 2 shows the crossbore that was the cause of the damage. This incident may not have occurred if the location of the underground infrastructure was identified before installation of the gas line, or if the use of technology to inspect the installation for the potential of a newly created crossbore was used. Enbridge's SSP is designed to reduce this risk by preventing new crossbores.

Figure 2: Crossbore from Ogdensburg, New York (2004)

<u>Program Description</u>

The Sewer Safety Program was initiated in order to prudently manage and mitigate the safety risks specific to sewer laterals and to prevent the inadvertent intersection with a natural gas pipeline. The SSP continues to address the inadvertent intersection of a sewer line with a natural gas pipeline, which is generally characterized by industry as a crossbore. This presents a safety risk if the crossbore is damaged during attempts to clear the blocked sewer line. In this scenario, natural gas could migrate into a building through the sewer line and create a potential for explosion.

Preventing legacy crossbore damages (an O&M expense) and preventing new crossbores (capital) are the fundamental focus points of the SSP. Preventing the creation of new crossbores is dependent on the continued work on locating underground infrastructure to ensure trenchless technology installation methods do not create a new risk, as well as the development of a process to capture relevant information about sewer laterals that have been identified as being cleared of any crossbores in the Company's geospatial information systems (GIS). Geospatial-enabled crossbore tracking is an integral part of the SSP wherein it allows recording of sewer lateral inspection clearances as well as the location of crossbore instances throughout the franchise area. Instances of crossbores will be analyzed to determine if trends can be identified that can assist with predicting where crossbores might occur. To date, no such trends have been adequately identified.

Since the SSP was initiated, crossbores have been successfully identified and rectified. Without the SSP, each of these locations could have led to a crossbore interaction with potentially damaging consequences. Fortunately, there have been no major incidents in Canada as a result of these intersections; however multiple incidents within the United States have been reported.

As part of incorporating SSP activities into Enbridge's standard construction practices, Enbridge will be mandating private sewer lateral locates for all new trenchless installations in 2013. This new construction requirement will help to ensure crossbores are not created.

The Company is currently implementing a geospatial records management and tracking process to allow electronic tracking of the Sewer Safety Inspections, legacy investigations and actual crossbore locations. The process will be an integral part of the Program wherein it will provide the ability to compile data that will assist in future sewer lateral locates and trends within the franchise area.

Capital Requirements

The capital budget request for 2014-2016 (shown below in Table 2) is to continue the execution of the SSP for new construction work and to develop the process to record sewer inspection information into the Company's GIS system.

Table 2: Capital Cost Summary ($000)

	Forecast		
Description	2014	2015	2016
Construction & excavation for trenchless installations	1,445	1,496	1,532
Relocations & relays to address legacy crossbores	50	50	50
Development & implementation of a new records management and tracking process	35	15	10
TOTAL	1,530	1,561	1,592

Notwithstanding compliance with the legal requirements, the activities incorporated in the SSP continue to deliver direct benefits to customers, the public and to Enbridge by mitigating the risk of injury and property damage. Avoiding the creation of potential new crossbores and recording sewer information in the Company's GIS achieves a reduction to integrity risk of the overall distribution system and are prudent expenditures.

SERVICE REPLACEMENTS – PROJECTS UNDER $ 2 MILLION OVER THE FORECAST PERIOD

Table 1: Service Replacement Projects Under $ 2 million ($000)			
	Forecast ($000)		
DESCRIPTION	2014	2015	2016
Bare Steel Drips (study & removal program)	255	-	-
Casing Study & Program	510	-	-
Chicago Fitting Study	204	-	-
EFV Program	500	604	733
Farm Tap Study	-	208	265
Inside Regulator Replacement	36	5	5
Jumper and Service Extension Study	408	208	212
WingLock Valve Study & Replacement	204	-	-
Total	2,117	1,025	1,215

CAPITAL REQUIREMENTS

STATIONS –REPLACEMENT AND UPGRADES

Summary

1. The station capital requirements for the forecast period (2014 to 2016) cover the needs for gate stations, district stations and the more complex or larger sales stations. Although the majority of the costs for station capital activities in this evidence relates to the need for replacement of all or part of the stations, in some case the capital requirements also address the need for capacity related modifications. All stations in the natural gas distribution system provide a control point in the network that regulates the pressure in the system (receiving at a higher pressure and delivering at a lower pressure), and/or measures the volume of natural gas passing through the stations to the downstream network or directly to a customer. The efficient and reliable operation of gate, district and sales stations is critical for Enbridge to maintain safe and reliable distribution of natural gas. Enbridge has identified station related capital requirements for the forecast period to ensure the continued supply of natural gas to over 2 million customers.

2. The capital work required at the pressure regulating stations has various drivers including safety and reliability, security, regulatory compliance, capacity, condition, age, and obsolescence. The proposed replacements and upgrades include a wide range of capital improvements extending from new installations to specific equipment component replacements and upgrades. Many of the stations also provide secondary functions such as natural gas conditioning, such as the heating of the natural gas and the injection of odorant. All of these systems and components are subject to the need for periodic replacement.

3. The Station Replacement and Upgrade capital requirement for the period of 2013 to 2016 is summarized in Table 1.

Table 1: Capital Requirements ($000s)

2013	2014	2015	2016
15,767	23,990	26,442	24,517

4. Table 2 provides a detailed breakdown of the programs included, which are:
   a. Gate Stations and Select District Station Upgrades
   b. District Station Replacements and Upgrades
   c. Commercial and Industrial Low Pressure Regulator Stations
   d. Paper Chart Recorder Replacement Program
   e. Station Replacement and Upgrade Projects Under $ 2 million

5. The capital requirements for Gate and Select District Stations upgrades or replacements are driven by safety and reliability risk mitigation, security concerns, compliance with codes and regulations, capacity requirements and finally, the condition, age or obsolescence of operating components or equipment. Gate Stations are defined as the pressure regulating and measurement stations where the custody of natural gas is transferred from transmission companies to Enbridge. Natural gas is measured, heated, pressure regulated, and odourized prior to entering distribution mains. These facilities are monitored through telemetering where station specific parameters are transmitted through Enbridge's telemetry system to Enbridge's Gas Control group. District stations are defined as pressure regulating stations located downstream of gate stations that further reduce natural gas pressure and feed lower pressure networks. Some district stations are monitored through telemetry systems. Some district stations require gas preheat

systems due to operational conditions. The capital requirements discussed in this evidence pertain to gate stations and those district stations that have telemetry and compounds. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 4, Attachment 1.

6. The capital requirements for District Station Replacements and Upgrades are driven by the same set of needs defined for Gate Stations. The District and Sales Station Equipment Replacement ("D&SSER") Program focuses only on district stations, and sales stations that supply delivery pressures greater than 2 psi. This program will target approximately 2700 sites for upgrades over the forecast period, ranging from component replacement to entire station replacements. These replacements and upgrades target specific risks associated with station age, condition and design, and represent an efficient means of both maintaining and improving the safe and reliable operation of the gas distribution network. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 4, Attachment 2.

7. Sales stations are defined as pressure regulating stations that reduce natural gas pressure and meter gas flow for delivery to customers. The capital requirement for the Commercial and Industrial Low Pressure Regulator (CLR) Stations, or sales stations, is based on the need for a systematic program to monitor and potential modify or replace these stations. The plan, which will include the forecast period, will to undertake a verification study of the CLR station population to further understand the conditions associated with these assets, define a sustainable program and implement a pilot project that includes replacement to the extent appropriate. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 4, Attachment 3.

8. The capital requirements for the Paper Chart Recorder Replacement Program will fund the replacement of approximately 300 paper chart recorders per year over the forecast period. The electronic devices replacing the existing paper chart recorders provide real-time pressure information that is accessible at a central control centre and eliminates the need for changing the paper charts on a weekly or monthly basis. This capital requirement is described in more detail at Exhibit B2, Tab 5, Schedule 4, Attachment 4.

9. Other station replacement and upgrade projects with a total capital requirement below $ 2 million over the forecast period are summarized at Exhibit B2, Tab 5, Schedule 4, Attachment 5.

10. Table 2 summarizes all of the direct capital requirements for the programs and projects associated with the replacement of stations and the upgrades of stations within the Company’s distribution network.

Table 2: Station Replacements and Upgrades Capital Requirement ($000)				
Description	Budget	Forecast Period		
	2013	2014	2015	2016
Gate Stations	6,642	12,160	10,440	7,060
District Stations	3,201	7,977	11,625	12,560
Commercial and Industrial Low Pressure Regulator Stations	2,000	1,530	2,341	2,388
Paper Chart Recorders Replacement Program	1,673	1,758	1,794	1,830
Station Replacement and Upgrade Projects Under $ 2 million	2,251	565	602	680
Total	15,767	23,990	26,442	24,517

GATE AND SELECT DISTRICT STATION UPGRADES

Summary

The efficient operation of gate and district stations is critical to Enbridge maintaining the safe and reliable supply of natural gas. Enbridge identifies capital upgrades for these stations in order to ensure the supply of natural gas to over 2 million customers. This evidence outlines the proposed capital projects for pressure regulating stations totaling $29.7 million over the forecast period. There are 74 pressure regulating stations within the scope of this evidence. They are used to step down line pressures at various points in the system from transmission line pressures of approximately 1,000 psi to pressures between 650 psi and 175 psi for delivery to Enbridge customers. The stations have secondary functions including natural gas conditioning. Natural gas conditioning includes odourization and temperature management. Heat control is required where gas pressures drop substantially causing rapid temperature change in the gas.

The capital work involved at the pressure regulating stations has various drivers including safety and reliability, security, compliance, capacity, condition, age, and obsolescence. The proposed upgrades include a wide range of capital improvements extending from new installations to equipment replacements and upgrades.

Enbridge considers capital efficiencies when identifying station improvements in addition to enhancing safety, reliability, and operational efficiency. Projects that are initiated mainly through a single driver are also assessed to determine any opportunities to coordinate additional work to fulfill other operational objectives. The capital requirements for the proposed program are set out in Table 1.

Table 1: Capital Requirement Summary ($000)				
Project Name	Budget	Forecast Year		
	2013	2014	2015	2016
Cookstown Gate Station		2,974	0	0
Gas Preheat System Risk Mitigation Project		2,616	715	715
Barrie Gate Station		0	3,192	0
25 Projects Each Under $2 Million		6,570	6,533	6,346
Total	6,642	12,160	10,440	7,060

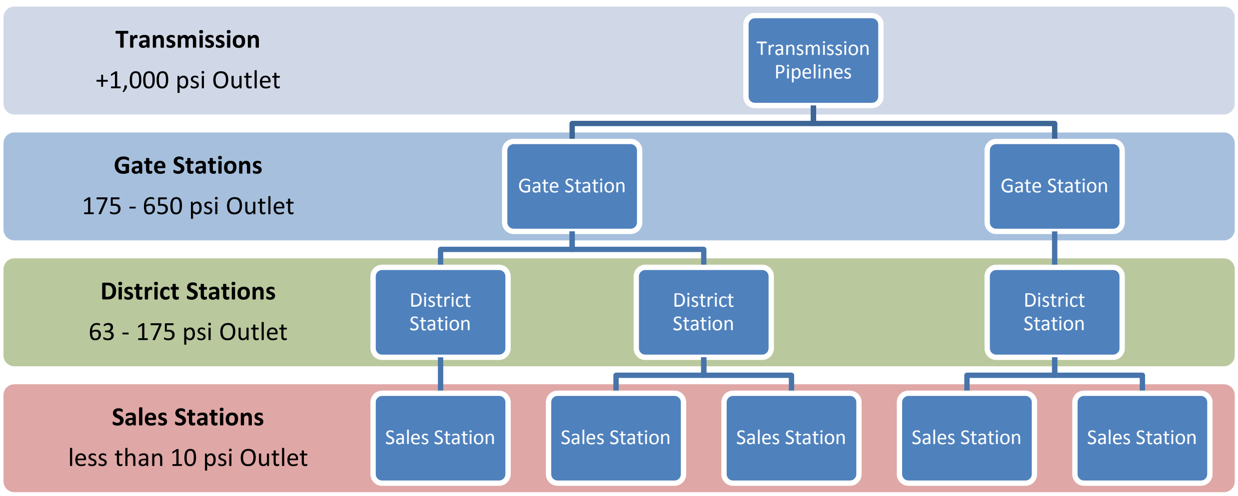
It should be noted that the capital requirement associated with the Gas Preheat System Risk Mitigation Project during the forecast period includes immediate mitigation to all gas preheat systems, detailed testing and analysis of one heat exchanger, and complete replacement of the oldest unit. In the event that the testing and analysis reveals the need for accelerated replacement on the 56 additional sites, there is no provision for this additional work in above forecast (approximately $750,000 per site).

Background

Types of Stations

There are three types of stations: gate stations, district stations and sales stations. Figure 1 illustrates a schematic of different stations within the distribution system.

Figure 1: Station Type Overview



Gate stations are defined as the pressure regulating stations where the custody of natural gas is transferred from transmission companies to Enbridge. Natural gas is measured, heated, pressure regulated, and odourized prior to entering distribution mains. These facilities are monitored through telemetering where station specific parameters are transmitted through Enbridge's telemetry system to Enbridge's Gas Control group.

District stations are defined as pressure regulating stations located downstream of gate stations that further reduce natural gas pressure and feed lower pressure networks. Some district stations are monitored through telemetry systems. Some district stations require gas preheat systems due to operational conditions.

Sales stations are defined as pressure regulating stations that reduce natural gas pressure and meter gas flow for delivery to customers.

The capital requirements discussed in this evidence pertain to gate stations and those district stations that have telemetry and compounds.

Regulatory Requirements

The Process Hazard Analysis (PHA), discussed further in this evidence, is used by Enbridge to meet risk identification, mitigation, and elimination requirements in the CSA Z662-11. Section 3.2 provides requirements for pipeline system integrity management and notes Annex N as a guideline. Operating companies are required to identify hazards, determine causes, and identify and eliminate or mitigate the risks.

Security requirements given in CSA Z246.1-13, Sections 9.3.7 and 9.3.9 identify the need to control access and monitor operator determined critical stations. Enbridge meets these requirements by identifying critical stations and implementing security measures (further discussed in this evidence).

In addition, municipal by-laws apply to pressure regulating stations depending on the location of the station, site layout, station design attributes, and equipment considerations. Enbridge meets these requirements by engaging the appropriate municipalities and complying with permitting processes.

Enbridge applies any additional regulation, code (i.e. the Ontario Fire, Electrical and Building Codes) and by-law requirements through prudent engineering design. Implications of these are included in multiple proposed projects in this evidence.

Project Drivers

In order to determine which capital projects are selected and when they are implemented, Enbridge has identified a series of project drivers. These drivers allow

Enbridge to assess the needs of a station and take into consideration the range of reasons to complete work. Either a single driver or a series of drivers can warrant a proposed capital requirement.

The following drivers are used to determine if capital projects are required:

- Safety and Reliability – in order to manage risks to workers and the public, safety is a critical driver for project selection. Reliability for our customers is ensured through a robust capital upgrade program.
- Security – gate and select district stations are located in increasingly heavily populated locations as cities expand and populations become denser. Security systems are critical to public safety to ensure that stations are protected.
- Compliance – changes in regulatory and municipal requirements drive certain components of capital projects.
- Capacity – ensuring that station capacity meets future downstream load requirements is critical to ensure the reliable supply of natural gas to Enbridge customers. This is particularly true in respect of Enbridge, given its continuing forecast customer growth.
- Condition/Age/Obsolescence – as equipment installed in stations becomes older, its reliability and maintainability decrease. Having system components with readily available parts enables effective and efficient operation and ensures the safe and reliable supply of natural gas to Enbridge customers.

In addition to the drivers above, PHAs are used to identify work that mitigates additional risks at stations. Enbridge uses PHAs as a tool to satisfy Z662 -11 requirements for integrity management and risk assessment.

A PHA is an extensive assessment of potential hazards, the results of which are used to identify improvements to processes that result in the mitigation or elimination of the identified hazards. A PHA is designed to identify hazards associated with a process which informs Enbridge's understanding of various operational risks. These processes include the activity of measuring, heating, regulating and odourizing (in the case of gate stations) natural gas at gate and select district stations. The analysis involves extensive contribution from station operators, design engineers, business partners, and other subject matter experts. During the analysis, hazards are identified and corrective actions are taken to eliminate them. This is done through procedural and design changes, process upgrades, and increasing employee and contractor awareness.

PHAs are completed on existing and newly constructed facilities. Currently, Enbridge has conducted PHAs on a gate station and a compressor station. A number of different methods are used during a PHA depending on the complexity of the process being analyzed. As a result of these PHAs, Enbridge has identified, and is in the process of mitigating, the identified risks by understanding what could go wrong at these facilities.

Program Description

Enbridge classifies capital expenditures for pressure regulating stations based on the type of work that is being done. Capacity or security of supply related projects typically involve the reconstruction of all, or part, of a regulating station. Station natural gas flow changes, as well as age and obsolescence, drive the need to undertake projects to upgrade the gas preheat systems at gate and select district stations. Additionally, odourant system upgrades are driven by capacity, safety, and age and obsolescence. Hazard mitigation work is identified through the PHA program.

Station Upgrades – Cambellford Gate Station Example

Enbridge relies on gate and district stations in order to ensure forecast downstream capacity requirements are met.

An example of a capacity related proposed project is Campbellford Gate Station. Downstream demand requirements at Campbellford Gate Station are forecast to increase to 12,800 m^3/hr in 2016 and will exceed the station capacity of 10,000 m^3/hr. In order to increase capacity the regulators will be replaced with a high capacity model. The odourant system will be moved to a separate building to contain the odourant storage tank and injection system in order to mitigate risks associated with spills and fire hazards. While capacity is the main driver for the proposed project, Enbridge will leverage the shutdown time of the station and crew mobilization to upgrade the odourant system. A security system will also be installed. In addition, risk mitigation projects will be installed, including a weather system, carbon monoxide and methane detection, communication redundancy, Remote Telemetry Unit (RTU) upgrades, and pressure relief valves (PRVs) on the glycol loop of the gas preheat system. This ensures the reliable supply of natural gas to Enbridge customers and the safe operation of the station, while capturing productivity and efficiency savings.

Gas Preheat Systems – Pelham Gate Station Example

During pressure regulation, natural gas goes through a temperature reduction. The Joule Thompson Effect governs the temperature drop in natural gas when pressure reduction occurs. Natural gas that is approaching or below 0 degrees Celsius after regulation has a detrimental impact on equipment reliability including the regulators themselves and downstream pipe and valves. Natural gas that is allowed to leave stations below 0 degrees Celsius will also negatively impact municipal infrastructure including roads and sidewalks.

The principal components of the gas preheat system are a gas fired boiler and a heat exchanger. Basically, the pressurized boiler heats and circulates glycol through a glycol loop to a heat exchanger which transfers the heat to the natural gas before passing through the regulator. A more complete description of the system is included in the Gas Preheat System Risk Mitigation Project detailed further in this evidence.

An example of an age and obsolescence project involving the gas preheat system is the one proposed for Pelham Gate Station. Due to the age of the boiler system and forecast capacity requirements, an upgrade to the boiler system is being proposed. New high efficiency boilers will be installed, reducing natural gas fuel consumption and increasing reliability. A security system will also be installed. In addition, risk mitigation projects will be installed, including a weather system, carbon monoxide and methane detection, communication redundancy, RTU upgrades, and PRVs on the glycol loop. The upgrades to Pelham Gate Station will maintain the safe and reliable supply of natural gas to Enbridge customers while maximizing efficiency by performing all of the work at the same time.

Odourant Systems – Vineland Gate Station Example

Odourant systems consist of bulk odourant storage tanks containing mercaptan and odourant pumps. The pungent mercaptan is added to the odourless natural gas so that natural gas can be easily detected and recognized. There is associated telemetry that connects the odourant pump to the station metering system that allows for the proper odourant injection rate. Odourant systems are a component of most gate stations and odourization is critical to taking transmission gas and bringing it into Enbridge's distribution system. Age, obsolescence, safety, and increased capacity requirements tend to drive odourant system related work.

An example of a safety and reliability driven project is the one proposed for Vineland Gate Station. Currently, the odourant injection pump exists in a multi-use building that does not provide the tank and pump a single means of secondary containment. The proposed upgrades to the station will include a full odourant system replacement to increase the storage capacity and include the pump and tank in single containment. A security system will also be installed. In addition, risk mitigation projects will be installed, including a weather system, carbon monoxide and methane detection, communication redundancy, RTU upgrades, and PRVs on the glycol loop.

Ensuring properly odourized natural gas reaches downstream customers is pivotal to the safety and reliability of the supply of natural gas to customers within Enbridge's network. Potential natural gas leaks remain readily detectable and the risk to customers is mitigated. Supplying natural gas that is not readily detectable (which is addressed through the addition of odourant) contravenes regulatory codes and Enbridge policy. Odourant system work is deemed critical to the functionality of gate stations.

Security

Enbridge has identified site security to be a critical component to ensure a safe and reliable supply of natural gas to customers, and worker and public safety. Through two pilot installations at large gate stations, Enbridge has refined its security system design and proposes access control and surveillance installations at gate and select district stations between 2014 and 2016.

Projects Over $2 Million

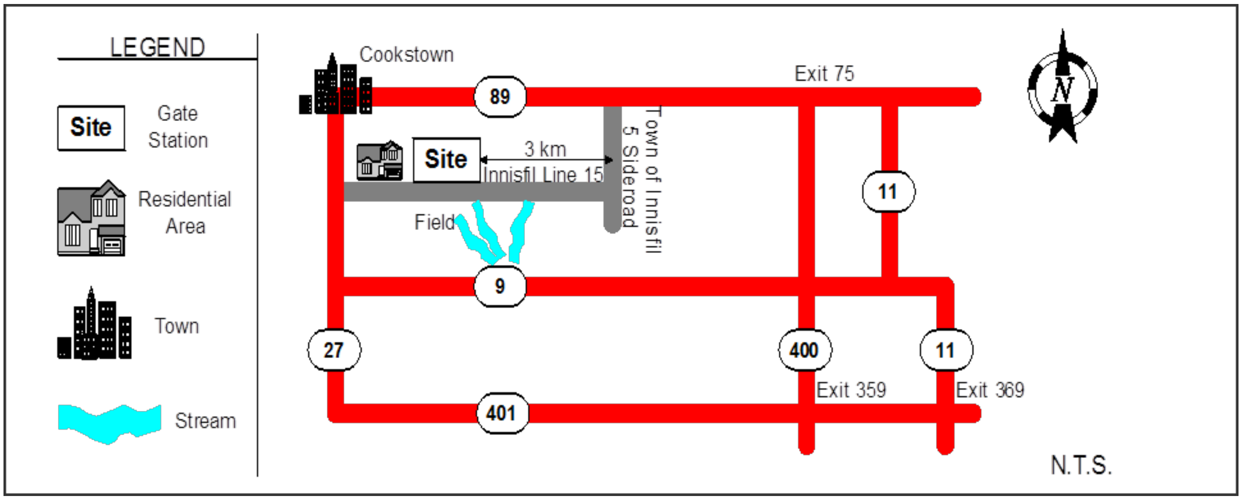
Cookstown Gate Station

Table 2: Project Summary	
Item	Description
Cost ($000)	2,974
Timeline	2014
Design Capacity	23,300 m^3/h
2016 Forecast Capacity	40,600 m^3/h

Project Description

The Cookstown Gate Station, shown in Figure 2 below, will have an upgraded pressure regulation station installed in an expanded section of the compound to meet forecast capacity requirements for 2016 that exceed the design capacity of the current station. The 2016 forecast requirements are being driven by the proposed 2016 Alliston Reinforcement. The upgrade will require the acquisition of additional property at the current station site. It will also include the replacement of existing equipment with new regulator runs, new odourant injection system, new gas preheat system, new metering, and new telemetry. It will also include required site preparations to accommodate the additional land and on site buildings. There are no practical or cost effective alternatives to the proposed work.

Figure 2: Cookstown Gate Station



Why the Work is Needed and Why is it Needed Now?

The current capacity of the Cookstown Gate Station is 23,300 m^3/h and does not sufficiently meet the 2016 forecast peak flow of 40,600 m^3/h for 2016. In order to ensure this future capacity is met, a new station must be installed.

The existing site cannot accommodate expansion therefore property will need to be acquired, impacting the scope of the capacity increase because the existing piping on site will need to be reconfigured and some existing buildings will need to be replaced. When new buildings are installed, municipal by-laws and applicable codes require specific property setbacks and building separations.

Description of Work

In order to increase the capacity of the station, the capacity of each component within the station needs to be upgraded. At Cookstown, this will result in the redesign and replacement of the following station components:

- Metering
- Telemetry
- Gas preheat system
- Regulation
- Odourant injection system
- Site buildings
- Security

In order for these components to be installed, land will need to be acquired to accommodate the station.

Capital Requirements Summary

See Table 3 for a breakdown of the proposed capital requirement.

Table 3: Project Cost Summary	
Item	Cost ($000)
Material	1,399
Labour	1,575
Total	2,974

What are the Benefits and Costs Savings?

Increasing the capacity of the Cookstown gate station will allow Enbridge to meet the projected capacity requirements for 2016. Prudent design of the new station will ensure that it can accommodate future network growth requirements and the addition of new customers. This will allow Enbridge to maintain the reliability of the network and provide adequate supply to the expanding communities of Cookstown and Alliston and other customers.

Capital Prioritization

This expansion is tied directly to the proposed reinforcement of the Alliston extra high pressure (XHP) running between Cookstown and Alliston. In order to meet forecast network demand within the Alliston system, a four phase reinforcement of the pipeline has been proposed (See Exhibit B2-3-1 Attachment 1 for Reinforcement Program). The four phases will include the installation of 13.6 km of NPS 8 XHP ST main and 3 km of NPS 6 XHP main from Cookstown to Alliston. The completion of the third phase of this reinforcement scheduled to occur in 2016 will require the increased station capacity of Cookstown Gate Station to be available.

Gas Preheat System Risk Mitigation Project

Project Description

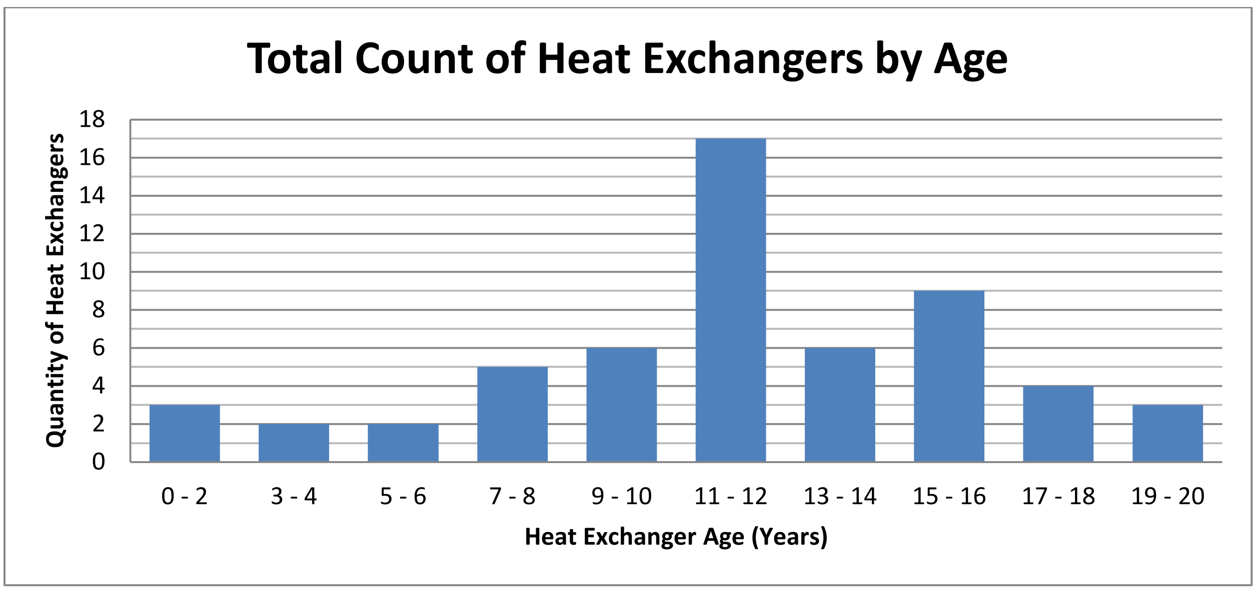
Gas preheat systems are installed at most gate and select district stations in order to prevent the natural gas from freezing during pressure reduction. Of the 63 pressure regulating stations with gas preheat systems, 57 sites utilize shell and tube heat exchangers in order to heat the natural gas. As Enbridge's heat exchangers age, the risk resulting from tube failures increases. A failure in the tube of the heat exchanger will cause a glycol spill, an uncontrolled release of natural gas at high pressure, a disruption in station flow and reduced station capacity, and a migration of natural gas in the gas preheat system resulting in the over pressuring of the boilers where combustion occurs. Mitigating the risk of a failure in the tube of a heat exchanger is critical to ensuring a safe and reliable supply of natural gas to Enbridge customers. In order to mitigate this risk, a three phased program has been developed.

The proposed program includes the removal, replacement and testing of the oldest heat exchanger in the system. It also includes the retrofit of the next two oldest heat exchangers with actuated valves on the heat exchanger and glycol loop of the preheat system. Pressure relief valves (PRVs) will be installed at all non-retrofitted stations to mitigate the most severe consequences of a tube failure. The proposed program will result in more extensive recommendations on the best approach to manage the risk of tube failures.

Background

As a result of an intensive PHA at Victoria Square Gate Station, risk mitigating recommendations for heat exchangers were proposed. In addition, Enbridge has identified that there is not sufficient information regarding heat exchanger life expectancy. The proposed recommendations and the age of heat exchangers in Enbridge's system (shown in Figure 3) have led to the need for further evaluation.

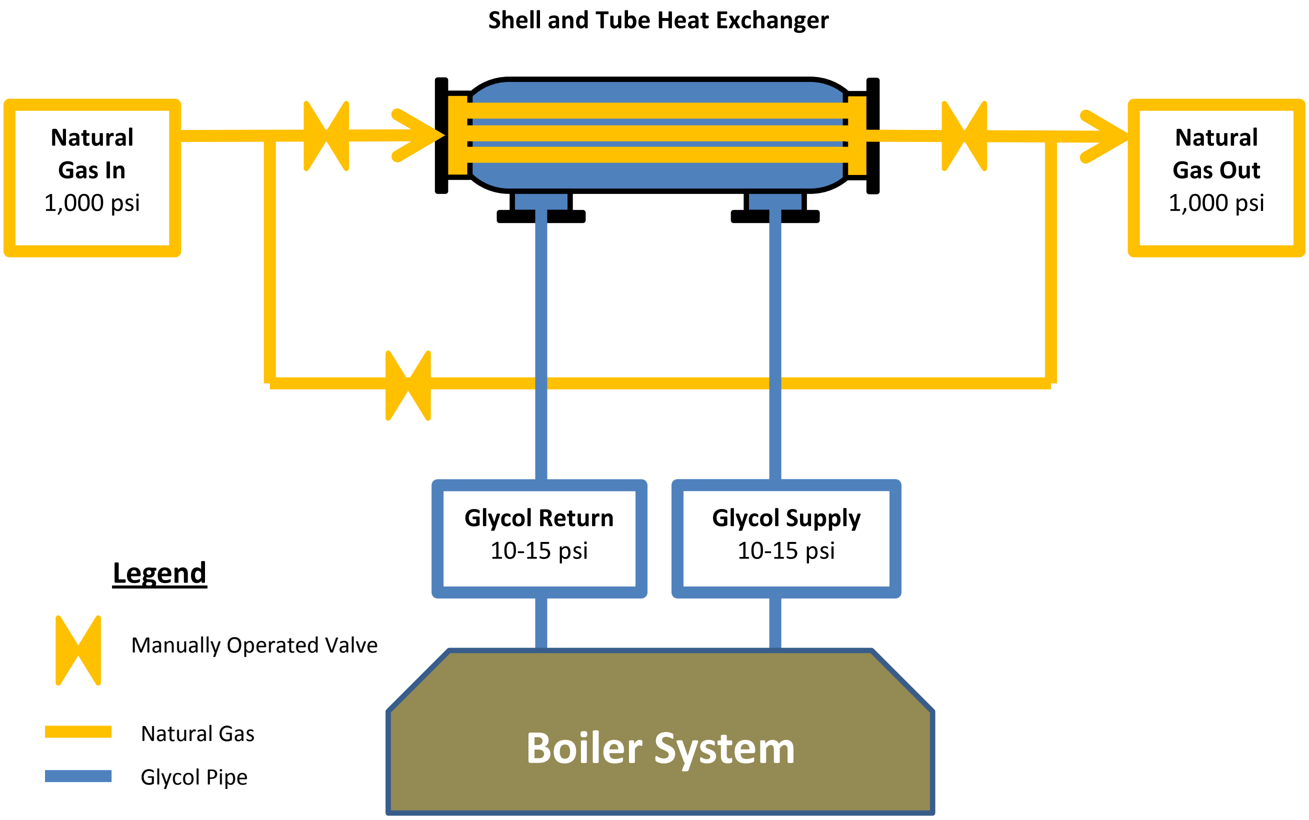
Figure 3: Heat Exchangers By Age



Existing Gas Preheat System Layout

Within Enbridge, gas preheat systems are comprised of boiler systems that heat glycol at low pressure that is then pumped in a continuous loop to a shell and tube heat exchanger. The glycol flows outside of the tubes and within the shell. The natural gas flows through the tubes and is heated in the heat exchanger. This prevents the natural gas temperature from going below freezing after pressure regulation. The layout of a typical gas preheat system at a pressure regulating station is shown in Figure 4.

Figure 4: Typical Station Layout



Why the Work is Needed and Why is it Needed Now?

During a tube failure, the current gas preheat systems do not have the capability to remote pressure sense and as a result, would not be directly observed by Enbridge Gas Control. A station shut down would be necessary to make the situation safe for site remediation.

Enbridge has identified that safety and reliability is substantially improved by adding control systems (including valve actuators and sensors) able to immediately isolate the heat exchanger in the event of a tube failure. This eliminates the risk of a glycol spill, high pressure natural gas leak, and overpressuring of the boiler system. In addition, valve actuation on the glycol loop prevents the overpressurization of the boiler system.

Enbridge recognizes the risk associated with tube failure in heat exchangers and that the likelihood of this mechanism of failure is not fully understood as it applies to Enbridge stations. Through the proposed program, Enbridge will be able to assess the condition of the heat exchangers and develop a prudent approach to retrofitting existing stations to mitigate the risk of tube failure.

Why the Proposed Work is the Preferred Alternative?

The proposed program will provide the system specific information that Enbridge needs in order to develop the most prudent approach to mitigating the risk of tube failure. The phased approach allows for Enbridge to get detailed information regarding the impacts of system operating characteristics on shell and tube heat exchangers over their lifecycle and will provide for a systematic approach to future retrofits.

Description of Work

In order to assess the current status of existing shell and tube heat exchangers, a three phased approach is outlined below.

Phase 1 – Risk Analysis (2014)

To understand the heat exchanger tube failure risk, Enbridge has included the following action steps in the first phase of its plan:

1. Remove and replace oldest heat exchanger (currently 19 years old) in the system and use it to:
    a. Perform and evaluate a non-destructive test (NDT) to provide information for testing the other heat exchangers in the system;
    b. Perform and evaluate a destructive test to further understand the nature and degree of deterioration and aging and verify the results of the NDT; and
    c. Install valve actuators on the replacement heat exchanger and glycol loop.

2. Retrofit the next two oldest heat exchangers (both 19 years old) with valve actuators

The heat exchanger replaced for testing and the next two oldest heat exchangers will be outfitted with valve actuators on both the upstream and downstream of the heat exchanger and on the inlet and outlet of the glycol lines. This will allow for the remote isolation of the heat exchanger should a tube failure occur.

Phase 2 – Assessment (2014 – 2015)

With the results of the analysis in Phase 1, Enbridge will assess and identify the most appropriate course of action. A combination of retrofits at the most critical facilities and upgrades when stations are rebuilt will be considered when identifying the most prudent implementation strategy. Phase 2 will develop evaluation criteria based on the assessment. These will be used to identify factors that increase the likelihood of tube failure. Stations with these factors will be assessed a higher priority, and will be retrofit sooner.

Phase 3 – Implementation (2014 – 2016)

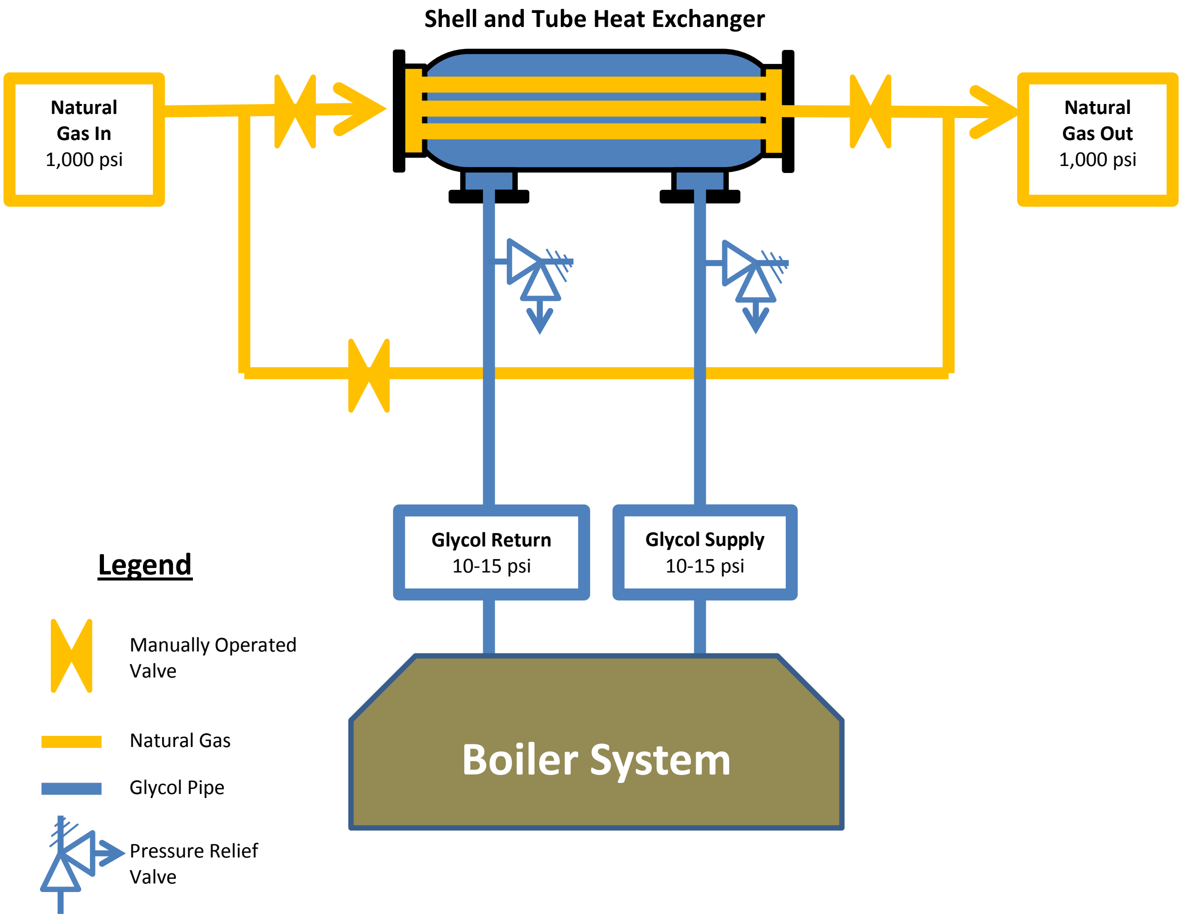
Enbridge proposes to retrofit the 54 gas preheat systems that are not included in Phase 1 with PRVs on the inlet and outlet of the glycol loop. This will mitigate the most severe consequence resulting from a tube failure (i.e. the overpressuring of the boiler system and release of high pressure natural gas into the boiler system where combustion occurs).

Enbridge will also execute on the implementation strategy identified in Phase 2. It will also include selective testing to validate any assumptions made in Phase 2. The completion of Phase 3 will see all gas preheat systems outfit with an appropriate mitigating strategy to eliminate the risks associated with tube failure in heat exchangers.

Installing Pressure Relief Valves

Install pressure relief valves on the supply and return lines of the glycol loop to prevent overpressuring of boiler system in the event of a tube failure. Figure 5 shows a conceptual layout.

Figure 5: Pressure Relief Valve Retrofit Concept



Capital Requirements Summary

Table 4 shows the cost breakdown for the heat exchanger risk mitigation project.

Table 4: Cost Breakdown ($000)							
Phase	Item	Cost Per Site	Planned Number of Sites	Year			Total
				2014	2015	2016	
1	Valve Actuation Retrofit	468	2	938	0	0	938
1	New Heat Exchanger and Actuation Retrofit	743	1	743	0	0	743
1	Testing and Analysis	220	1	220	0	0	220
3	PRV Retrofit	55	39	715	715	715	2,145
TOTALS				2,616	715	715	4,046

The above budget contemplates the following work:

- Of the 57 shell and tube heat exchanger sites:
    - The oldest will be removed, replaced, tested and retrofitted with valve actuation
    - The 2 next oldest heat exchangers will be retrofitted with valve actuation
    - And 39 sites with heat exchangers will undergo PRV retrofits

- An additional 15 sites will undergo PVR Retrofit work, the costs of which are included in the total project capital requirements outlined in Table 1 in the line item for the 25 projects each under $2 million

What are the Benefits and Costs Savings?

Through the three phase approach, Enbridge will be able to identify the most appropriate and cost effective retrofit strategy by understanding the risk to Enbridge heat exchangers. As a result of the proposed analysis, Enbridge will be able to identify and assess practical alternatives and define a strategy for the retrofit scope and scheduling, adopting a prudent approach to capital spending.

Capital Prioritization

The three phase program proposed will allow Enbridge to gain system specific information in order to identify the most effective implementation strategy. The benefits of this three tiered implementation strategy mitigates the most critical consequence at each station with gas preheat systems, while maintaining a prudent approach to capital spending.

Barrie Gate Station

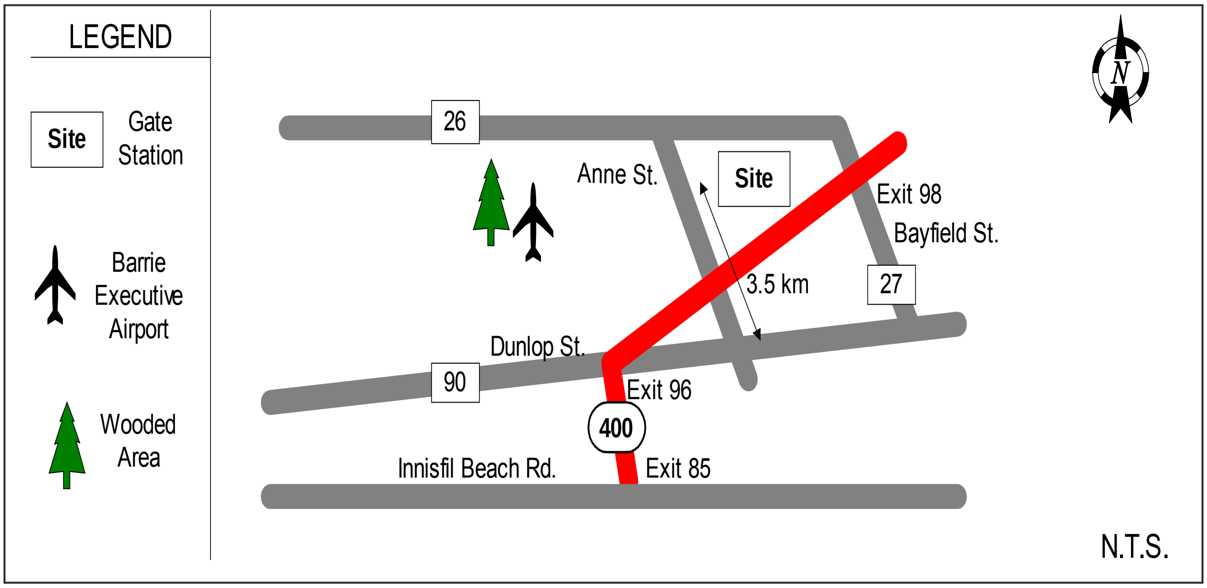
Table 5: Project Summary	
Item	Description
Cost($000)	$3,192
Timeline	2015
Design Capacity	46,900 m^3/h
Forecast Capacity	57,500 m^3/h

Project Description

The design capacity of Barrie Gate Station, shown in Figure 6, will have an upgraded pressure regulating station installed to meet forecast downstream demand requirements. The planned upgrades to the regulator runs will extend the station's ability to maintain adequate supply to Enbridge's downstream customers.

Station capacity upgrades will require enhancements to other peripheral systems at Barrie Gate Station. These systems include gas preheat system (boilers, heat exchanger, glycol piping, etc.), flow measurement, telemetry systems and odourant systems. While capacity related work is being done at this station, Enbridge will move the odourant system to a separate building to meet containment requirements. There are no practical or cost effective alternatives to conducting the proposed work. For example, using an alternate site for a complete rebuild would significantly increase the overall cost of the project.

Figure 6: Barrie Gate Station



<u>Why the Work is Needed and Why is it Needed Now?</u>

The current capacity of Barrie Gate Station is 46,900 m^3/h and does not sufficiently meet the 2016 forecast flow of 57,500 m^3/h. In order to ensure this future capacity is met, station upgrades must be completed.

The upgrades are necessary to increase station capacity which will maintain security of supply for customers within the Enbridge distribution network. The upgrades planned for 2015 are the next step to increasing capacity at Barrie Gate Station and follow the installation of a new larger capacity station inlet from TransCanada Pipelines Ltd (TCPL) completed in 2012.

<u>Description of Work</u>

The proposed upgrade work at Barrie Gate Station involves replacing existing pressure regulating equipment with equipment that will support forecasted network demands for years to come. These upgrades are the next step in station upgrades at Barrie Gate

Station which began in 2012 with the installation of a new larger capacity station inlet from TCPL.

The proposed increase in station capacity will require upgrades to other existing systems at Barrie Gate Station. These systems include:

- Gas preheat system
- Metering
- Telemetry
- Odourant injection system
- Security

The existing gas preheat system is not adequate to meet the proposed station capacity. The forecasted network demands will require a larger gas preheat system to heat an increased flow of natural gas through the station at peak demand periods. The proposed gas preheat system will consist of new boilers, heat exchangers, glycol pumps and piping, boiler controls, and a new boiler building.

The existing flow measurement equipment is not suitable to measure the forecasted station flow and will need to be replaced. Existing telemetering systems will need to be upgraded to a system designed to monitor the proposed new station equipment.

The existing odourant system will need to be upgraded to meet the forecasted station flow. The system will also be moved to a separate building to meet containment requirements. The proposed odourant system will consist of odourant storage tank and building, odourant panel, odourant injection point and odourant tubing lines.

Capital Requirements Summary

See Table 6 for a breakdown of the proposed capital requirement.

Table 6: Project Cost Summary	
Item	Cost ($000)
Material	1,845
Labour	1,347
Total	3,192

What are the Benefits and Costs Savings?

Increasing the capacity of the Barrie gate station will allow Enbridge to meet the projected capacity requirements for 2016. Prudent design of the new station will ensure that it can accommodate future network growth requirements and connection to new customers. This will allow Enbridge to maintain the reliability of the network and provide adequate supply to downstream customers.

Overview of Projects Under $2 Million

Table 7 includes a list of additional projects whose individual capital requirements over the forecast period is less than $2 million.

Table 7: Capital Requirements for Projects Under $2 Million by Forecast Year ($000)

Project	2014	2015	2016	Drivers
Grimsby Gate Station	410	0	0	Safety and Reliability, Security, Compliance, Capacity
Keele & Finch Feeder Station	1,871	0	0	Security, Compliance, Capacity
Niagara Gate Station	410	0	0	Safety and Reliability, Security, Compliance, Capacity
Vineland Gate Station	410	0	0	Safety and Reliability, Security, Compliance, Capacity
Yonge and Gamble Feeder Station	961	0	0	Compliance, Capacity
Bathurst Gate Station	0	684	0	Safety and Reliability, Security, Compliance, Capacity, Condition/Age/Obsolescence
Beamsville Gate Station	0	410	0	Safety and Reliability, Security, Compliance, Condition/Age/Obsolescence
Campbellford Gate Station	0	465	0	Security, Compliance, Capacity
Lancaster Gate Station	0	410	0	Safety and Reliability, Capacity, Compliance

Table 7: Capital Requirements for Projects Under $2 Million by Forecast Year ($000)				
Project	2014	2015	2016	Drivers
Metcalfe Gate Station	0	798	0	Security, Compliance, Capacity
Oshawa Gate Station	0	410	0	Safety and Reliability, Security, Compliance, Condition/Age/Obsolescence
Yonge and Steeles Feeder Station	0	849	0	Safety and Reliability, Compliance
Consumers Rd Feeder Station	0	0	959	Safety and Reliability, Compliance
Dale Gate Station	0	0	959	Compliance, Capacity
Deep River Gate Station	0	0	1,517	Safety and Reliability, Security, Compliance, Condition/Age/Obsolescence
Pelham Gate Station	0	0	409	Safety and Reliability, Security, Compliance, Condition/Age/Obsolescence
Boiler Room Ventilation Upgrade	138	138	138	Safety and Reliability, Compliance
Carbon Monoxide Detectors	86	86	86	Safety and Reliability, Compliance
Electrical Upgrades	605	605	604	Safety and Reliability, Compliance

Table 7: Capital Requirements for Projects Under $2 Million by Forecast Year ($000)				
Project	2014	2015	2016	Drivers
Methane Detectors	86	86	86	Safety and Reliability, Compliance
RTU Upgrades	601	601	599	Safety and Reliability, Compliance
Station Security	661	659	659	Safety and Reliability, Security, Compliance
Ultrasonic Meter Upgrade	202	202	202	Safety and Reliability, Compliance
Weather Station Upgrade	59	59	59	Safety and Reliability, Compliance
Wireless Station Communication	70	70	70	Safety and Reliability, Compliance
Total	6,570	6,533	6,346	

Capital Requirements

A summary of all proposed capital requirements is included in Table 8.

Table 8: Capital Requirement Summary ($000)

Project Name	Forecast Year		
	2014	2015	2016
Cookstown Gate Station	2,974	0	0
Gas Preheat System Risk Mitigation Project	2,616	715	715
Barrie Gate Station	0	3,192	0
25 Projects Each Under $2 Million	6,570	6,533	6,346
Total	12,160	10,440	7,060

The variation in the capital requirements over the forecast period is the result of the anticipated completion of several large scale projects in the early years. There are currently no forecast additional major projects.

DISTRICT AND SALES STATION REPLACEMENT PROGRAM

Summary

The District & Sales Station Equipment Replacement (D&SSER) program focuses only[1] on District/Headers Stations, and Sales Stations (supplying 2 psi or greater). This program will target approximately 2700 sites for upgrades over the forecast period, ranging from component replacement to entire station replacements. Stations are concentrated points of pressure control, and therefore concentrated points of risk. These replacements target specific risks associated with station age, condition and design, and represent an efficient means of both maintaining and improving the safe and reliable operation of the gas distribution network.

This evidence is prepared to provide explanation of the capital requirements for station replacement work of approximately $32 million over the forecast period (2014-2016). The District & Sales Station Equipment Replacement program will require additional capital investment beginning in 2017.

Table 1: Capital cost summary

Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION / YEAR	2013	2014	2015	2016
District and Sales Station Replacement	3,201	7,977	11,625	12,560

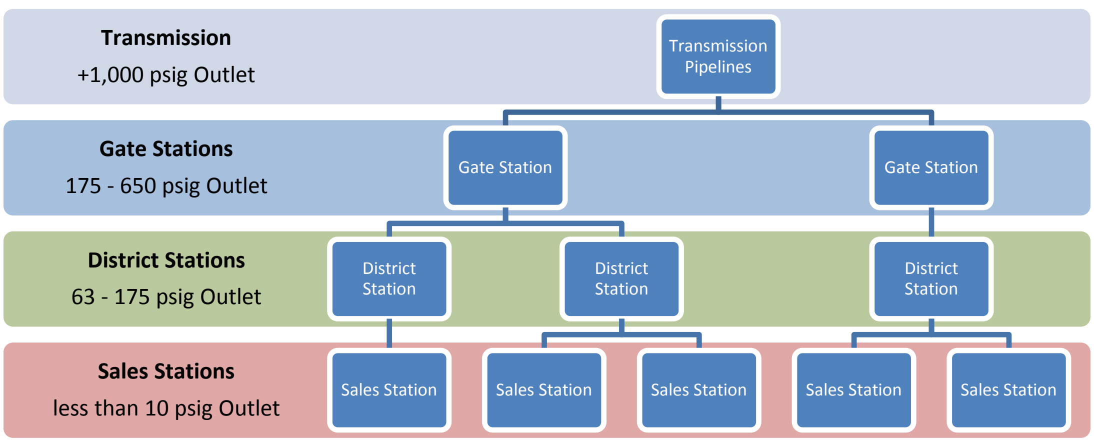
[1] Other evidence documents address programs for gate/feeder stations, low pressure sales stations (LPDMS program), and low pressure residential/small commercial meter sets.

Background

Pressure regulating stations are essential to customer safety and reliable gas delivery. Every station regulates gas from a higher pressure to a lower pressure.

Within this program, over 14,300 stations deliver gas to the distribution system, and to commercial/industrial customers in the GTA, Ottawa and Niagara regions. There are two basic categories of regulator stations within this program: District Stations and Sales Stations.

Figure 1: Enbridge Measurement and Regulating Station Hierarchy



All these stations[2] include regulators that control gas pressure and flow, and overpressure protection devices that limit pressure in downstream piping. These devices need to function properly to safely and reliably deliver gas. If a station failure occurs, the gas received at the inlet side of a station may not be reduced to the lower pressure for which the lines and equipment are designed to receive downstream. This has the potential to negatively affect all assets and property downstream as Figure 1 illustrates. The first scenario shows normal network operation of two networks; while

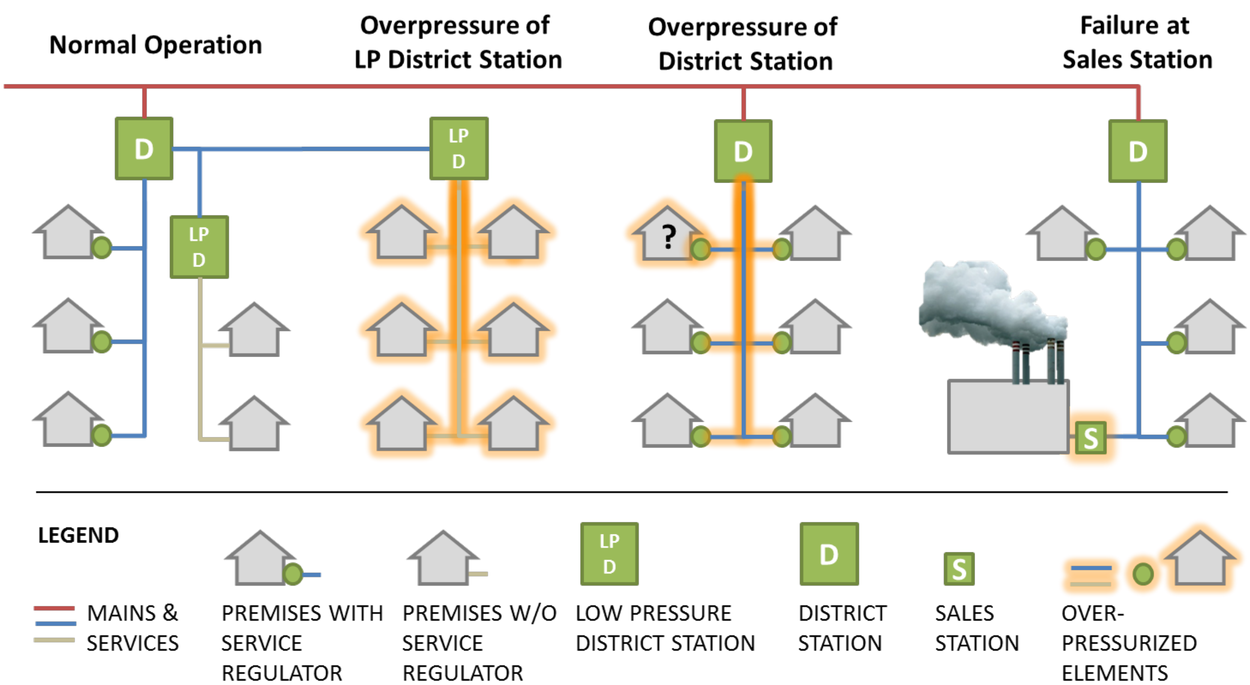
[2] Exception: certain large customers with "Sales Meter Only" stations accept gas without pressure regulation.

the next three scenarios show overpressure and failure situations (described the figure caption). For this reason, it is important to deal with the threats to the proper operation of these systems must continue to be well understood and effectively mitigated across the entire station population.

While historical replacement criteria focused on station capacity and condition (e.g. corrosion, valve operability), Enbridge has recently undertaken a critical and holistic approach to station replacement, to ensure that old designs remain suitable for present operating conditions (e.g. inline inspection, velocity), code compliance and increasing awareness of risk.

As is clearly shown in Table 1, this has created an acceleration of capital spending for this asset category. Additionally, this year the Company will spend in excess of the 2013 capital budget for this asset category.

Figure 1 Schematic of normal station operation, and consequences of station failure. Overpressure of an LP District Station will affect all downstream mains, services and customers, as there are no service regulators. Overpressure of a District Station will affect all downstream mains and services; depending on the severity, the service regulator may or may not mitigate effects on customer supply piping. Failure at a sales station may affect customer property and supply piping, depending on the type of failure.



Program Description

The existing station population employs a variety of regulators and station designs, some of which date back to the 1960s. These stations are part of a regular maintenance program, and Enbridge has captured performance and reliability data in the form of trouble call and maintenance history. Stations are an asset class with unique requirements, as evidenced by Enbridge's asset management programs, and the functional reorganization that created Network Operations (responsible for station selection, maintenance, and network monitoring).

The new holistic approach to managing district and sales station assets, in conjunction with station data, yielded six population groups considered to have elevated network operation threats; each of these groups is summarized below.

Station Groups

1. Stations with Insufficient Valves / Test Points

	2014	2015	2016
$1000	1,500	1,537	1,576
# Stations	40	77	79

At the time of their installation, these stations were considered suitable for their application and were designed without the valve and test points necessary to perform periodic inspections. To improve safety, Enbridge believes it is vital to perform periodic inspections to verify regulator lock-up and relief set-points[3], consistent with industry standards. Without performing these periodic inspections, there is reduced probability that the station will function as intended upon component failure or upset condition. This program is a continuation of an existing capital replacement program.

Proposed mitigation: Each site will be evaluated to determine priority and whether the station is a candidate for in-field retrofits, taking into consideration customer disruption. Complete station replacement is considered the prudent approach for stations where conditions are unsuitable (e.g. corrosion), or that require extensive in-field retrofit to add valves/test-points.

2. Remediation of Electronic Devices

	2014	2015	2016
$1000	2,013	2,013	--
# Stations	805	805	--

Historically, devices for monitoring pressures and flows were pneumatic paper charts. Over time, these devices transitioned to electronic volume correctors and automatic meter reading technologies. Since there is a possibility for the release of flammable gas in the

[3] The operating company is required to document frequency of inspections/test to ensure pressure control and pressure relief devices remain in a safe operating condition. [CSA Z662-11, s.12.10.5]. Lock-up refers to the regulator's ability to shut-off tightly when there is no downstream demand for gas. Relief set-point refers to the pressure at which the relief begins to open and relieve gas to the environment.

vicinity of pressure regulating stations (through external damage, maintenance activities or abnormal operating condition), these devices must comply with requirements for installation in a hazardous area (per Ontario Electrical Safety Code and CSA 22.1). A recent gate station Process Hazard Analysis raised awareness of electrical requirements. At district and sales stations, field observations indicate similar findings.

Proposed mitigation: Move the existing device to a satisfactory distance, or replace the device with one having suitable rating for the existing location is the prudent approach for this stream of work. Both approaches will involve re-wiring connections. Enbridge plans to complete this work by end of 2015.

3. Stations with Obsolete Regulators

Obsolete regulators are defined as regulators that meet (at minimum) one of the following criteria: spare parts unavailable, no longer approved for use in new installations, or both a history of poor performance and no longer manufactured.

	2014	2015	2016
$1000	1,014	2,600	2,954
# Stations	104	217	235

It is challenging to maintain these stations because it is not possible to repair (lack of spare parts), replace (lack of new stock), or easily service small regulator populations (training, confidence and spare parts). Proactive replacement of these stations will improve the safe and reliable distribution of gas.

Proposed mitigation: Complete station replacement is considered the prudent approach due to age of asset and labour-intensive work required to replace regulators on site (new regulator models may not fit in existing space available).

4. Stations in Below Ground Boxes

	2014	2015	2016
$1000	300	300	300
# Stations	4	4	4

Some stations are installed in below ground boxes due to space constraints and municipal requirements. These stations are often infiltrated by water (and in the winter, road-salt) which accelerates corrosion thereby decreasing station lifespan. Water removal must be completed prior to station inspection, and can be complicated due to possible contamination or ice formation. These scenarios decrease the reliability and performance of the station. Furthermore, worker safety may be compromised through the handling of contaminated water and non-ergonomic working conditions. For these reasons, the prudent approach is to bring stations above grade where municipalities will grant permission to do so, or secondarily to re-configure the existing stations.

Proposed mitigation: Complete station replacement is considered the prudent approach to resolve corrosion and access/egress concerns, subject to the practical limitations outlined above.

5. Low Pressure District Stations

	2014	2015	2016
$1000	1,500	1,500	1,500
# Stations	20	20	20

Low Pressure networks do not have service regulators downstream of the station. Therefore, the station's overpressure protection system is the only defence mechanism against an over-pressure incident. Due to the elevated reliability requirement of the over-pressure protection system, this group of stations will be studied to determine if regulator replacement is required, or if additional overpressure protection is required (e.g. slam shut[4] devices).

[4] Slam-shut refers to a device that provides over-pressure protection through containment; the valve closes at a set-pressure to prevent over-pressure situations and subsequently must be manually reset.

Proposed mitigation: Complete station replacement is considered the prudent approach to ensuring reliable performance of overpressure protection systems on LP stations. Installation of additional components will be considered where existing space permits.

6. Stations with Series Boot-Style Regulators

	2014	2015	2016
$1000	1,650	3,675	6,225
# Stations	12	44	83

Boot-style regulators use flexible elements[5] and upstream gas pressure to limit pressure and flow in the downstream pipeline. Over-pressure protection is provided by a second boot-style regulator installed in series. Enbridge operating history has revealed that stations employing this design are susceptible to failure due to debris/particulates, hydrates, or sulfur deposits. Examples of over-pressure incidents are summarized below:

- Keswick (>10 yrs. ago): Debris caused failure of both pressure control and over pressure protection, resulting in 200psi fed into 65 psi network.
- Balm Beach (>10 yrs. ago): Water content following hydrostatic test caused failure of both pressure control and over pressure protection, resulting in 200 psi into 65 psi network.
- Palgrave (2001): Debris caused failure of both pressure control and over pressure protection, resulting in 285 psi fed into 175 psi network. Suspected source of debris was relocation work.
- Leslie & Wellington (2011): Hydrate formation (suspected) caused failure of both over pressure control and over pressure protection, resulting in 266 psi into 175 psi network.

[5] Flexible elements are known as “boots” or “sleeves”, and the associated regulators are known as “boot-style” regulators. Both upstream gas pressure and the flexible element are used to positively seal-off upstream pressure when there is no demand for gas.

Following the Keswick incident, Enbridge implemented a policy change requiring mandatory boot replacement every five years. Despite this policy change, there is still room for improvement via design changes to the overpressure protection system. New technology now enables different methods of over pressure protection, such as the use of slam-shut devices or dissimilar regulators in series.

Proposed mitigation: Modifications to existing stations and policies, such as individual component replacement and increasing the frequency of boot exchanges, will be investigated and implemented if suitable. Where space-constraints, asset age or condition precludes these options, complete station replacement is considered the prudent approach for this group of stations. Transition to slam-shut overpressure protection will also reduce emissions.

Figure 2 Condition of typical below ground district station for complete replacement.

Based on the historical performance and analysis of risk, Enbridge proposes to mitigate the risks through station and component replacement. These replacements will ensure code compliance, customer safety and reliable gas distribution.

Work Description for Station Replacements

Station replacements will be prioritized based on an assessment of risk allocated to station characteristics (e.g. age, station configuration, components), and adjusted for individual site conditions. (e.g. corrosion, valve operation, etc). All replacement stations will be sized/selected with input from System Analysis on the required capacity to meet current and future needs. Depending on the site conditions and replacement station size, station replacement work may involve replacement between above ground valves/flanges, or excavation back to the main to replace station risers. Enbridge's preferred approach to replacing existing stations is the installation of pre-fabricated standard designs. This limits customer disruptions and is generally a more cost effective approach.

Work Description for Electronic Device Replacements

Sites falling within this program have been identified based on records of installed electrical devices, and work is underway to remedy the sites considered highest risk. Each site will be assessed to determine corrective actions required. If the existing installation is found to not meet current code and standards, it will be corrected either through modification of the existing installation (e.g. moving the device, changing the wiring connection) or upgrading the device to a newer model having electrical ratings that permit installation in closer proximity to the station.

Capital Requirements

The District & Sales Station Equipment Replacement program requires a capital investment of $32.1 million over the forecast period (2014-2016).

Table 2 Capital Cost Summary for District & Sales Station Equipment Replacement

Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION / YEAR	2013	2014	2015	2016
INSUFFICIENT VALVES/TEST POINTS	$855	1,500	1,537	$1,576
REMEDIATION OF ELEC. DEVICES	$380	2,013	2,013	$0
STATIONS WITH OBS. REGULATORS	$276	1,014	2,600	$2,954
BELOW GROUND BOXES	300	300	300	$300
LOW PRESSURE DISTRICT STATIONS	695	1,500	1,500	1,500
BOOT STYLE STATIONS	695	1,650	3,675	6,225
TOTAL	3,201	7,977	11,625	12,560

The increase spend over the forecast period is a function of the increased number of stations replaced.

The financial summaries above is based on the number of stations falling within each risk group, estimating a unit cost for station (or device) replacement[6], and the annual

[6] Includes equipment cost and associated installation cost. All figures are expressed in current dollars (2013).

volume of work[7]. While exact station costs vary with station type, station size, location and installation method, general estimates can be developed for various station types:

- Replacement of stations insufficient valves/test points: $20,000/ea.
- Correction of Electrical Compliance (per site): $2,500/ea.
- Replacement district station: $75,000/ea.
    - Applies to district stations having obsolete regulators, below ground boxes, low pressure district stations, and boot-style stations.
- Replacement of station with obsolete regulators:
    - Small sales station with type S301D regulator: $5,000/ea. (assume 75/yr.)
    - Large sales station or small district with (other type of) obsolete regulator: $12,000/ea.

[7] Depending on the work-stream, the quantity was based either on completing the sub-program within a given time period (e.g. completing non-compliant electronic devices within 2 years) or completing a given quantity of stations per year.

Appendix

Only a portion of district and sales stations fall within the scope of this program, and of these, only a portion will be addressed in the forecast period (refer to the section "Program Description"). The total quantity of stations falling into the six station groups is summarized in Table 3, both in total, and by station function (low pressure district, district and sales stations).

Table 3 Quantity of District & Sales Stations

	1350 LOW PRESURE DISTRICT STATIONS	3350 DISTRICT STATIONS	9600 SALES STATIONS
INLET	Up to 175psi (HP)	Up to 500 psi	Up to 500 psi
OUTLET	0.25psi (LP)	175psi (HP) or 25-55psi (IP)	Typically 2, 5, 10 psi
BOOT STYLE STATIONS 1130*	20	900*	210
INSUFFICIENT VALVES, TEST POINTS 400	200	200	--
STATIONS WITH OBSOLETE REGULATORS 4150**	100	500	3550**
OTHER	FEED LP NETWORKS 200	BELOW GROUND BOXES 20	ELECTRONIC DEVICES 1750***

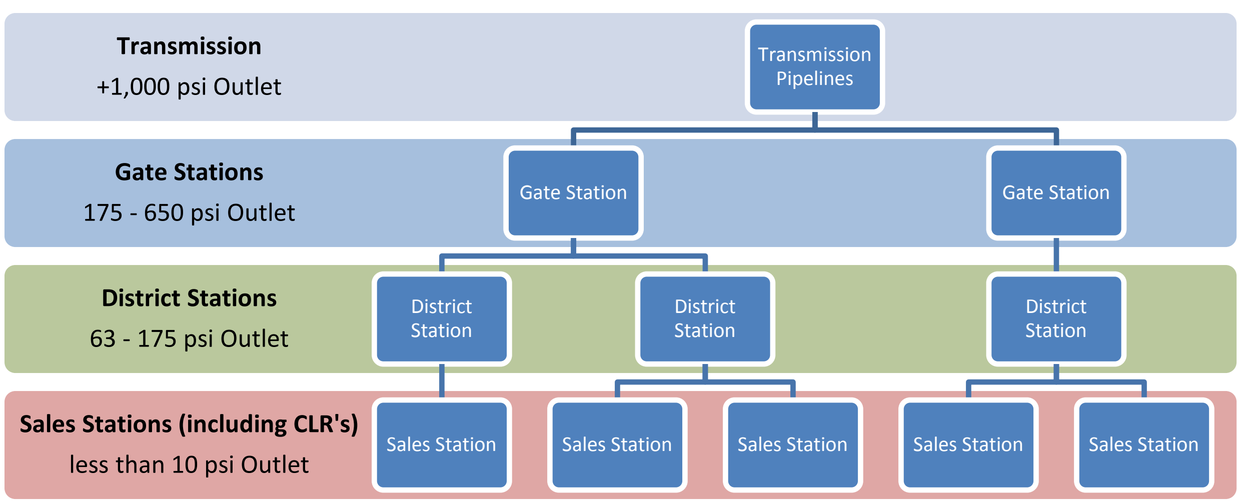
*approx. 40 out of scope (within station compounds) **includes 2800 stations with Type S301D regulators ***estimated number of stations requiring remediation of electronic devices.

COMMERCIAL AND INDUSTRIAL LOW PRESSURE REGULATOR STATIONS

Summary

There are approximately 105,000 commercial and industrial low pressure measurement and regulator (CLR) stations which are low pressure Sales Stations some of which were installed in the 1950s. There are two categories of CLR's. First, approximate 80,000 have a simple single regulator configuration and are essentially larger versions of the regulator and meter equipment attached to a typical home. The second group is the balance consisting of approximately 25,000 of these installations which are complex configurations which may contain up to three regulators. All 105,000 of these stations are included in this program and these costs are not duplicated in any other capital program.

Figure 1: Station Type Overview



The low pressure regulators associated with these CLR stations are aging and their condition requires monitoring. The plan is to undertake a verification study of the CLR station population over the forecast period to further understand the conditions associated with these assets, define a sustainable program and implement a pilot project that includes replacement to the extent appropriate.

The capital costs for the CLR program over the forecast period are identified in Table 1 below.

Table 1: CLR Program Capital Costs ($000)				
	Budget	Forecast		
Year	2013	2014	2015	2016
Station Replacements	$2,000	$1,530	$2,341	$2,388

<u>Background</u>

A natural gas low pressure regulator is a valve utilized by the natural gas industry to reduce pressure to 0.25 psig for this group of stations, which ensures that the customer's natural gas equipment can operate safely and effectively. As regulators are mechanical devices they are subject to failure. Although regulator failures are infrequent events, the consequences can be significant (loss of supply or unsafe condition).

CLR stations comprise a total of 105,000 meter sets in Enbridge's distribution network. CLRs can be categorized as a middle ground between smaller residential meter sets and larger Sales Stations. CLRs are made up of small commercial and industrial diaphragm and rotary meter sets and associated regulators providing customers with low pressure delivery. There are 80,000 diaphragm meters and approximately 25,000 rotary that can contain up to three regulators (See Figure 1 and 2). Additionally, approximately 1,000 of these are more complex and contain installations that can have multiple regulator runs, operator and monitor regulators and/or external pressure sensing lines (see Figure 3).

Figure 1: Typical CLR Rotary Meter Set with Single Regulator

Figure 2: Rotary Meter Set with Multiple Regulators

Figure 3: Complex Regulator with Sense Lines

Table 2 gives an approximate breakdown of the types of metering and regulation, the number of installations and current operating, maintenance and upgrade programs. CLR installations are indicated in blue.

Table 2: Regulation Categories

	Customer Type	Type of Metering	Type of Regulation	Delivery Pressure	Approximate Number of Installations	Regulator Replacement/Maintenance Programs
	Residential	225/400 Diaphragm	None or Simple regulator	0.25 psi	1,900,000	Meter and Regulator Replacement Program
CLR	Small Commercial	400/800 Diaphragm	None or Simple regulator	0.25 psi	80,000	Replace as Required
	Commercial & Industrial	Rotary	Simple regulator	0.25 psi	24,000	Replace as Required
	Commercial & Industrial	Rotary	Complex Station	0.25 psi	1,000	Replace as Required
	Commercial & Industrial	Rotary & Turbine	Complex Station	>2 psig	14,300	District Station Program

There are current and proposed programs for residential regulators and district stations that address the operating requirements of these stations and meter sets.

For the CLR population, many were not installed with a configuration that would allow field testing to confirm ongoing proper operations. As a result, only visual inspections are performed. A visual inspection does not confirm the correct operation of these regulators. Enbridge currently lacks the same performance data for the CLR population as it has for the residential regulator population. Without this information Enbridge does not know the performance characteristics for the CLR regulator population.

Accordingly a sample study of the CLR population was conducted in 2010/2011 to determine the condition of these assets. A sample size of 344 CLR installations was inspected in the field. Of the 344 samples, 226 required repairs, with an approximate capital/O&M split of 85%/15%. This study identified the following risks to the CLR population:

- Corrosion/Degradation
- Manufacturer/Construction Defects
- Equipment Malfunction
- Third party damage
- Environmental causes
- Operator error

These threats can all lead to over pressure of gas to downstream appliances, loss of containment in the customers premise or the loss of supply, resulting in a potential safety incident whereby public safety is compromised or the customer impact of no supply. While the results of this study were representative of one operating region, it was recognized that a broader study was required to understand the population of these assets across the Enbridge system.

In 2012, Enbridge commenced an investigative study to evaluate the condition of the CLRs, conduct the necessary mitigation to ensure that these regulators perform safely and reliably, and to design a long term preventive maintenance program.

Preliminary results of laboratory testing performed on 223 regulators, revealed that 9% of the relief valves did not meet the Company's over pressure protection specifications. All of the regulators that did not meet the specification were of an older vintage (over 30 years).

The preliminary conclusion from the laboratory testing indicates that further sampling and testing is needed to understand the conditions associated with this population of assets and to define a sustainable program. Once a suitable program is in place, customers will benefit from improvements to safety and reliability of the distribution network.

The need for an overall program is required as defined by the CSA Z662 code, 12.10.5 Pressure-control, pressure-limiting, and pressure-relieving devices.

Program Description

The CLR program will involve a combination of the following:

1. For the balance of 2013 and into 2014 the Company will conduct additional inspections of targeted CLR's to identify those risk and condition issues that are identifiable from a field inspection. Where appropriate, replace the regulator(s) and retain for laboratory analysis.
2. Over the same period, the Company will continue with the laboratory study to determine the mix of CLR's in operation and to better understand their performance characteristics.
3. The development of a risk based program in 2014 for different station configurations informed from the field inspections and the laboratory results.

4. The implementation of the pilot program in 2015 and 2016. This pace will allow Enbridge to sample a broad cross section of these sales stations and develop a sustainable maintenance and inspection program based on this information.

The risk based approach will take into consideration the overall condition and configuration of the CLR. The criteria to determine prioritization is as follows:

- Vent leak, condition and compliance
- Relief valve leak, condition and compliance
- Station supports and fasteners condition
- Station access and egress
- Station protection (meter barriers)
- Riser condition
- Ability to perform maintenance checks

Station upsizing or downsizing will be completed as required to optimize both from a cost perspective as well as for appropriately meeting the customer needs.

The Meter Replacement program and the CLR program will be synchronized to the extent possible to reduce customer downtime and costs.

Capital Requirements

The CLR program over the forecast period of 2013 – 2016 is identified in Table 3 below.

Year	2013	2014	2015	2016
Spend ($000)	$2,000	$1,530	$2,341	$2,388

The costs for 2014 are associated with continuing the study and laboratory testing of these regulators. Costs for 2015 and 2016 are associated with rolling out the pilot, which will involve the rebuilding of approximately 630 priority CLR installations, at an average estimated unit cost of $7,500.

PAPER CHART PRESSURE RECORDER REPLACEMENT PROGRAM

Enbridge monitors the pressure in its pipelines, because maintaining pressure within established safe operating limits is necessary to ensure the safe and reliable delivery of gas. Pressures that are above the operating limit can present a safety concern and pressures that are below the operating limit can cause customer outages. Historically, Enbridge has monitored pressure using a combination of our Supervisory Control and Data Acquisition System (SCADA) and paper chart recorders. A paper chart recorder is a mechanical device that records the pressure trend onto a piece of paper (the chart) which is then manually collected and replaced in the field on a weekly or monthly basis.

The paper chart recorder has limitations. The recorded data is drawn on a paper chart which must be manually delivered to an analyst at Enbridge for interpretation. There is a time lag in notification to alert Enbridge that the pressure was too high or too low in a system that is monitored with a paper chart recorder. In some instances, the lag may be unacceptable as the first notification to Enbridge that the pressures are too high or too low, may be from the public.

The purpose of this initiative is to modernize the process of monitoring pressures, by installing electronic devices which will replace the existing paper chart recorders and provide real-time pressure information to a central control centre. Any future pressure monitoring requirements will be met with the electronic devices.

Enbridge has been working with the gas industry since the early 1990's to encourage the development of an electronic device that will replace the paper chart recorder. Since its inception, the technology has matured from a reliability, capability, and price standpoint such that replacing the paper chart recorder with an electronic version is now prudent. As of January 2013, Enbridge has installed over 200 devices across the gas distribution network. Enbridge's forecast capital spending totals $5.3 million over the forecast period to continue its paper chart recorder replacement program and to install any incremental electronic pressure recorders to address growth or distribution network system changes. Enbridge is on track to replace the remaining paper chart recorders over the next four years.

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Paper Chart Recorder Replacement and Adds	1,673	1,758	1,794	1,830
Units (#)	300	300	300	300

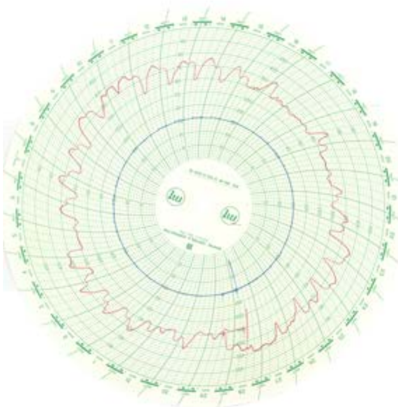
The benefits of replacing the paper chart recorders with electronic pressure recorders include;

1. Electronic pressure recorders can send alarms when low pressure or high pressure situations occur allowing Enbridge to immediately dispatch an Enbridge employee to investigate.
2. The availability of real time pressure data will help the Company better understand current pressure conditions which will aid Enbridge in making proactive operating decisions. This is particularly beneficial in upset or emergency conditions.
3. The accuracy, accessibility and the ease with which the data can be shared is better than with the paper chart recorder. This continues to support the verification of Enbridge's network models. As can be seen from figure 2, the paper charts must be manually interpreted and converted to data files for

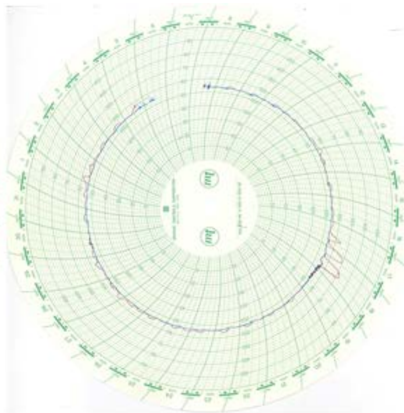
analysis. Figure 3 shows the tabular output from an electronic pressure recorder which is much easier to analyze.

4. The reduction in the manual effort associated with changing the paper charts on a weekly or monthly basis will result in a net cost reduction. This will partially offset the need to hire additional resources due to system growth. No additional resources are needed to manage the information available from the electronic pressure recorders.

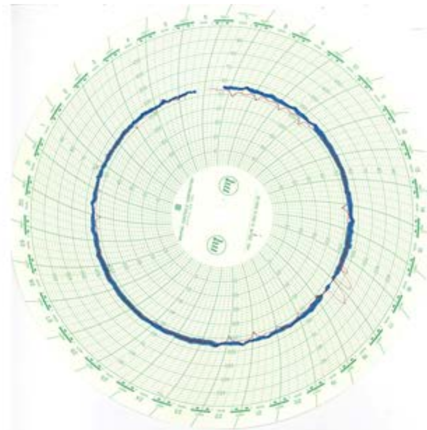
Figure 1 : Photo of Paper Chart Recorder and Electronic Pressure Recorder



Typical Paper Chart Recorder Data Collection



Paper chart recorder showing a spike in inlet pressure



Water damage that can destroy data

Figure 2 : Examples of the data displayed on a Paper Chart

ERX Detailed Report

Report Generation Date: Thursday, May 16, 2013 **Report Period: From: 5/15/2013 12:00:00 AM To: 5/16/2013 11:59:00 PM**

Date	Time	Pressure (PSI)(P1) NOP Range (250 - 485)	Highest Pressure (PSI)(P1)	Average Pressure (PSI)(P1)	Lowest Pressure (PSI)(P1)	Pressure (PSI)(P2) NOP Range (265 - 285)	Highest Pressure (PSI)(P2)	Average Pressure (PSI)(P2)	Lowest Pressure (PSI)(P2)	Average Voltage (V)(P3)	Case Temp.
05/15/2013	12:00 AM	469.52	472.16	467.10	458.84	274.28	276.56	274.53	272.31	8.16	15.29
05/15/2013	1:00 AM	460.68	469.52	464.61	460.68	274.01	274.94	273.59	271.83	8.16	14.83
05/15/2013	2:00 AM	459.81	460.69	460.38	457.82	274.78	275.92	274.46	272.33	8.16	14.10
05/15/2013	3:00 AM	471.33	472.21	465.57	458.05	275.29	276.31	274.43	271.68	8.16	13.29
05/15/2013	4:00 AM	460.29	472.23	465.57	458.06	275.08	276.49	274.36	271.80	8.16	12.48
05/15/2013	5:00 AM	471.37	471.37	465.47	458.08	275.96	277.10	274.59	271.86	8.16	11.84
05/15/2013	6:00 AM	469.55	471.37	465.13	456.33	274.11	276.78	274.51	272.04	8.16	11.21
05/15/2013	7:00 AM	457.67	469.56	463.79	455.45	273.03	276.84	274.41	271.93	8.16	10.67
05/15/2013	8:00 AM	466.36	466.97	459.02	453.64	275.16	276.74	274.41	271.56	8.16	10.49
05/15/2013	9:00 AM	461.71	468.74	465.54	461.65	275.26	277.83	274.49	271.77	8.16	10.85
05/15/2013	10:00 AM	466.06	469.61	466.89	461.98	273.29	277.55	274.61	271.88	7.80	11.66
05/15/2013	11:00 AM	458.97	470.48	464.52	456.76	275.57	277.38	274.49	271.87	8.13	12.21
05/15/2013	12:00 PM	462.37	470.57	465.92	455.85	275.07	276.72	274.60	271.85	8.13	13.20
05/15/2013	1:00 PM	463.80	470.23	461.37	456.95	275.12	276.10	274.11	271.63	8.14	13.74
05/15/2013	2:00 PM	458.04	470.43	463.82	457.15	275.05	276.59	274.28	271.51	8.14	14.29
05/15/2013	3:00 PM	461.08	470.42	461.52	454.50	273.80	276.20	273.88	271.35	8.14	14.23
05/15/2013	4:00 PM	466.89	469.54	467.08	460.80	273.86	277.02	274.87	272.77	8.14	14.20
05/15/2013	5:00 PM	468.49	468.49	461.36	455.83	274.62	276.20	273.60	271.46	8.15	14.22
05/15/2013	6:00 PM	457.15	469.54	462.18	457.15	275.33	276.25	273.88	271.73	8.16	14.38
05/15/2013	7:00 PM	459.91	470.42	463.62	457.15	272.70	276.36	274.07	271.12	8.16	14.65

Figure 3 : Example of data provided by Electronic Recorders

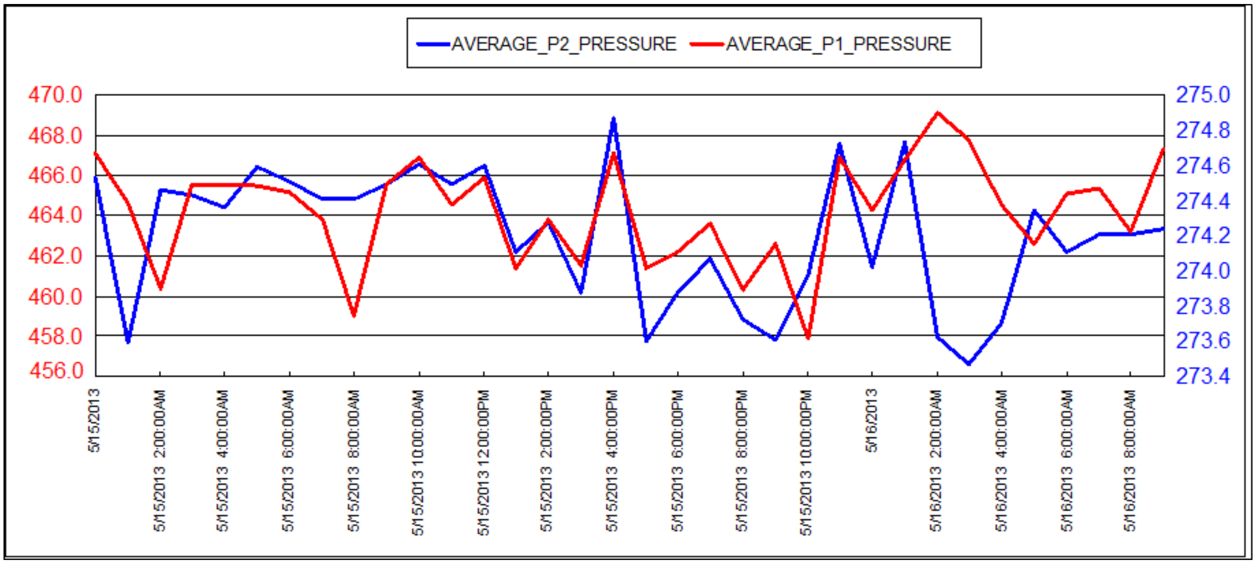


Figure 4 : Example of how data can be easily analyzed

Station – Projects Under $ 2 million 2014 to 2016

Table 1: Station Projects Under $ 2 million ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Remote Control Valve Study and Installation	-	515	617	680

SYSTEM INTEGRITY AND RELIABILITY – OTHER PROGRAMS AND PROJECTS 2014 - 2016

Overview

1. Over the forecast period there are two programs and one project included in this grouping of evidence. These are the Meter and Regulator Replacement Program, the Distribution Records Management Program and the Envision Extension project. These programs and project are included in this grouping given that they generally support multiple operating assets (mains, service or stations) or cover a unique aspect of the operating system (residential and small commercial meters and regulators).

2. Further information is provided for the Meter and Regulator Replacement Program in this evidence under Exhibit B2, Tab 5, Schedule 5, Attachment 1, for the Distribution Records Management Program under Exhibit B2, Tab 5, Schedule 5, Attachment 2 and for the Envision Extension project under Exhibit B2, Tab 8, Schedule 2, /c Attachment 3.

3. Table 1 provides the forecasted capital requirements for both programs and the Envision Extension project.

Witnesses: A. Creery
C. McCowan

Table 1: System Integrity and Reliability – Other Programs and Projects ($000)				
Description	2013	2014	2015	2016
Meter and Regulator Replacement Program	23,520	24,169	25,911	28,115
Distribution Records Management Program	9,386	9,639	8,740	7,695
Envision Extension Project	–	8,000	8,000	–
Total	32,000	41,808	42,651	35,810

METER AND REGULATOR REPLACEMENT PROGRAM

Summary

Through the Meter Replacement program, Enbridge manages compliance with Measurement Canada regulations. The Meter Replacement program involves the verification and installation of new meters, and the removal, testing and repair or disposal of old meters. The pace of meter replacement is increasing as a result of the implementation of Measurement Canada's new S-S-06 standard. In addition, other measurement devices are replaced as a result of damage, upgrade, and other reasons.

Regulators are replaced at the same time as the meters are replaced so as to avoid a separate visit. This approach improves safety and efficiency and improves the customer experience by combining two activities in one visit to the premise.

The cost of the program for the purchase of new meters and regulators and their installation is contained in Table 1.

Table 1: Capital Cost Summary ($000)

DESCRIPTION	2013	2014	2015	2016
Meter Replacement – EGIA Compliance	10,627	12,255	13,477	14,857
Distribution Regulator Replacement	7,506	7,639	7,784	7,927
Meter Replacement – Other	5,387	4,275	4,650	5,331
TOTAL	23,520	24,169	25,911	28,115

<u>Background</u>

A typical customer meter set contains two major components; a measurement device (meter and/or instrument) and a pressure regulating device (regulator). Measurement devices are utilized to measure the amount of “gas bought and sold” as defined in the federally legislated *Electricity and Gas Inspection Act and Regulations* (“EGIA”). EGIA ensures measurement accuracy and is very prescriptive. Enbridge must ensure all its measurement devices remain in compliance with EGIA and is audited annually by Measurement Canada.

Both the meter and regulator are mechanical devices and over time require replacement in order to ensure accuracy and public safety. Inaccurate measurement through the meter will result in customers being billed incorrectly. Failure of regulators can create an unsafe condition. As a result, Enbridge is continuing with its ongoing replacement programs to ensure the proper operation of these two vital pieces of equipment.

<u>Meters</u>

All measurement devices (such as meters and instruments) utilized to measure the amount of gas bought and sold in Canada must meet EGIA specifications. Measurement Canada imposes very prescriptive criteria for the tolerances under which this equipment must operate in the field. Enbridge must demonstrate that all aspects of its meter sampling, maintenance and replacement comply with these criteria in order to be accredited by Measurement Canada to validate the accuracy of measurement devices.

The methodology used to identify in-service groups of meters that must be removed for evaluation is specified under the old LMB-EG-04: *Statistical Sampling Plans for the Verification and Re-verification of Electricity and Gas Meters*, or the new S-S-06: *Sampling Plans for the Inspection of Isolated Lots of Meters in-service*. Enbridge has recently received Measurement Canada accreditation under the new S-S-06 standard (previously accredited under LMB-EG-04 standard).

Under the former LMB-EG-04 sampling criteria, diaphragm gas meters were sampled and evaluated, and those that failed to achieve extensions were identified for removal the year their seal expired. Whereas with the new S-S-06 specification, utilities must remove meter populations from service prior to degradation of performance severe enough to cause a meter group not to achieve compliance. The purpose of these stricter requirements is to tighten tolerances and enhance accuracy criteria. This change significantly impacts utilities in that it results in an increase in the meter removal volume over previous years.

Meters grouped in the Meter Replacement Other category include those identified for replacement as a result of damage to the meter, changes to customer load requirements, and/or billing disputes. Also included are rotary meters, turbine meters and instruments which are purchased sealed from the manufacturer and do not qualify for sampling inspection under Measurement Canada S-S-06 specification and must therefore be exchanged prior to the end of the year in which their seal expires.

<u>Regulators</u>

The Canadian Standards Association (“CSA”) Z662 Industry Code for Oil and Gas Pipeline Systems (Section 12.4.9, Part C) requires pressure in a residential building to be maintained under 2 psi. A domestic natural gas regulator is a valve utilized by the natural gas industry to reduce pressure to pressures appropriate for domestic appliances. This requirement ensures that the customer’s natural gas equipment can operate safely and effectively. As regulators are mechanical devices they are subject to failure. Although regulator failures are infrequent events, the consequences can be significant (loss of supply or unsafe condition).

Regulators are replaced at the same time as meters because of their relatively low cost compared to the cost of replacing the regulator at a later date or at the time of failure. The benefit of replacing it earlier avoids the costs with the additional call and avoids a potentially hazardous situation or loss of supply.

Program description

There are three components to Enbridge's Meter Replacement program, including: Meter Replacement – EGIA Compliance, Distribution Regulator Replacement, and Meter Replacement – Other.

Meter Replacement –EGIA Compliance is the ongoing program that meets Measurement Canada's requirements under their S-S-06 Compliance Sampling Specification. It involves the evaluation of approximately 500,000 devices per year, of which fewer than 20,000 are physically removed as samples and inspected at Enbridge's meter facility. This sampling assists Enbridge in the determination of which meter groups require replacement in order to ensure we remain in compliance with all of the EGIA requirements. The forecasted program units and capital requirements are provided in Table 2.

Distribution Regulator Replacement is the ongoing program to replace distribution regulators at the time of meter replacement. Enbridge has determined that, given the age of meters that require replacement, the likelihood of the corresponding regulators meeting replacement criteria is high. Enbridge will re-evaluate the need for the frequency of regulator replacements at some point beyond the current forecast period.

Meter Replacement – Other is the continuing work associated with the replacement of meters that are not covered under S-S-06 but as required under EGIA specifications. This category also includes meter replacements resulting from damages to meters, changes to customer load requirements, and/or billing disputes.

Forecast Replacement Volumes and Associated Costs

The capital requirements associated with the Meter Replacement program are identified in Table 2 below and reflect compliance with requirements in EGIA. The capital requirements associated with the replacement of other meters along with the cost to maintain accreditation are also identified in Table 2.

Table 2: Forecast Program Units and Capital Requirements

		Budget	Forecast		
YEAR		2013	2014	2015	2016
In Service Measurement Devices	Forecast Total Devices	2,073,200	2,114,942	2,156,208	2,199,912
	Devices Due for Evaluation	479,056	488,470	498,237	508,335
Meter Replacement – EGIA Compliance	Units	84,853	87,151	89,980	90,872
	Total Cost ($000)	10,627	12,255	13,477	14,857
Distribution Regulator Replacement	Units	107,691	109,196	111,203	113,097
	Total Cost ($000)	7,506	7,639	7,784	7,927
Meter Replacement – Other	Units	25,000	25,000	25,500	26,000
	Total Cost ($000)	5,387	4,275	4,650	5,331
TOTAL ($000)		23,520	24,169	25,911	28,115

As noted above, the capital requirement associated with the Meter Replacement – EGIA Compliance category will increase as a result of the implementation of Measurement Canada's new S-S-06 standard.

The decrease in Meter Replacement Other costs in 2014 through 2016, relative to 2013 costs, is due to the conclusion of the current rotary meter replacements program being completed in 2013. Unit costs for the meters which are included in the Meter Replacement Other category vary given the mix of meter types being replaced.

DISTRIBUTION RECORDS MANAGEMENT PROGRAM

Summary

The Distribution Records Management (DRM) program is a broad set of initiatives to enhance the asset records management practices – standards, processes, technologies, and governance required to manage an asset record throughout its lifecycle.

Asset records contain information crucial to effective analysis, decision making and asset management. An asset record can be in paper form or in electronic form, stored within an information system. The quality and accessibility of this information, when used as an input to decisions, directly affects the safe and reliable operations of the system, employee and public safety, and the environment.

The asset records support Enbridge's decisions such as:

- the assessment as to whether and where to build new distribution assets,
- the specifications to which new distribution assets should be designed,
- the type and frequency of inspections and maintenance that should be conducted,
- the verification and decisions regarding the maximum operating pressure of the pipelines,
- the practices and procedures that should be in place to keep workers and the public safe,
- the decisions about the repair or replacement of assets and
- the decision to decommission assets.

Asset records management refers to the processes, technologies and governance required to manage an asset record throughout its lifecycle. Within the asset records

management practice at Enbridge, the goal of the program can be summarized as follows:

> To enhance the ability to operate safely and reliably and to support effective operational decisions with asset records which are verifiable, traceable, complete, accessible, accurate and timely.

Although asset record management has been a continuous focus for Enbridge, there are a number of factors that are influencing the continuing evolution of Enbridge's asset records management practice. These include the asset management and process safety management disciplines, industry developments and trends, emerging legislative requirements for a formalized Records Management System, and issues such as the increasing volume of records and the age of some records. Further, there are a number of technologies (such as barcoding and Global Positioning Systems (GPS)) available to assist in meeting the goal of the asset records management program.

The DRM consist of a number of initiatives designed to achieve the above stated goal. These initiatives include the digitization and storage of existing and new data, three dimensional laser scanning, the capture and use of GPS and barcode data for existing and new assets and the identification and augmentation of asset as-built information. A specific initiative included in the DRM program address the digitization required to complete the Maximum Operating Pressure Verification (MOP) program.

Incremental capital is required for the enhancement of the asset records management practices – standards, processes, technologies, and governance necessary to provide the information required in support of operational decisions. The incremental costs related to DRM are summarized in Table 1:

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Pipeline	2,560	1,790	1,783	1,367
Stations	2,730	3,370	2,500	2,000
GPS	3,000	3,000	3,000	3,000
MOP Records Management	1,096	1,479	1,457	1,328
TOTAL	9,386	9,639	8,740	7,695

Background

Enbridge is a company that has been in business for over 160 years. Throughout that history, the Company has had practices in place to manage asset records. Over time, these practices have evolved with the changing needs of the business and with the advent of technology. For example, over successive generations of computer systems, some records that were originally manual have been converted to an electronic tabular form, and more recently to a geospatial form. Although some records have remained manual and continue to be generated through manual processes (e.g. field notes), Enbridge's direction is to capture and manage all records in an electronic form to achieve the goal stated above.

After more than 160 years of growth and evolution, the scope and scale of the asset records management challenge is significant. To provide some context, Enbridge has over 36,000 km of pipelines, over 2 million services, over 14,000 stations and other related distribution network assets required in order to service over 2 million customers. To operate, maintain and expand these assets requires the continual management of a considerable volume of records. For example, there are over 3 million asset records and over 20 million event records currently stored in the work and asset management system with nearly 1 million new event records generated each year. In the past eight years more than 2 million document based records have been scanned and stored so they can be accessed electronically. There are more than 2 million other document based records that need to be scanned.

A separate program is underway to verify the maximum operating pressure (MOP) of Enbridge's highest pressure pipelines (the extra high pressure pipelines). This program is in response to one of the central themes in the findings and recommendations of the United States National Transportation Safety Board (NTSB) investigation into the 2010 San Bruno, California incident. One of the major findings of the NTSB was that incomplete pipeline records and/or a lack of MOP substantiation can be a significant contributing factor to a major incident. These findings were further adopted and implemented through the U.S. Department of Transportation Pipeline & Hazardous Materials Safety Administration (PHMSA) via advisory bulletins (Jan 10, 2011 PHMSA Advisory Bulletin and May 7, 2012 PMHSA Advisory Bulletin) which requires U.S. operators to verify and report that the maximum allowable operating pressure determinations for their pipelines are supported by verifiable, traceable and complete records. Enbridge views this as the current industry standard and has adopted same through the implementation of the MOP Verification program and the DRM program.

In 2012, a pilot MOP verification made apparent that the application of the asset records management practices within the DRM program are also required by the MOP program. As such, the records management related MOP activities and costs have been aligned with the DRM program. The Engineering work required for the MOP program has been described separately.

Program Description

As stated above, Enbridge's goal is to enhance the ability to operate safely and reliably and to support effective operational decisions such as those required in the MOP program. This has led Enbridge to undertake a number of initiatives collectively referred to as the Distribution Records Management Program (DRM). The DRM will enhance processes and governance through the use of technology to improve the way information is captured, managed, stored and used.

The DRM Program is and will continue to utilize the following technologies:

- Global Positioning System (GPS):
    - GPS provides accurate and timely information on asset location. Capturing this information in the Geospatial Information System (GIS) supports improved integrity inspection and analysis, identification of leaks relative to gas assets, damage prevention, and emergency response.
- Digitization:
    - This allows for locally stored paper records to be preserved and made easily accessible on-line to field and office personnel. An example of this would be the information needed for and utilized by the MOP Verification program.
- High definition video:
    - This provides a current panoramic video recording of the equipment and site at priority Gate stations. It allows for a visual representation of assets and the relationship between them to support training, emergency response and station maintenance activities.

- Extended Computer Aided Design (CAD);
  - This involves the use of CAD on station drawings to include electrical and additional non-gas assets in support of Process Safety Management.
- 3D laser scanning:
  - This allows for capturing a three dimensional view of existing above ground assets in priority Gate stations. This view includes gas and non-gas assets. This supports training, emergency response and station maintenance activities.
- Barcoding:
  - Barcoding provides material traceability back to the manufacturing process; asset attributes (pipe thickness, diameter, etc.), a unique ID, and can be scanned to provide fast identification with a low error rate.
- Mobile Devices:
  - This involves the modification of existing mobile devices such as laptop computers, hand held GPS devices and even mobile phones, to allow for the capture and access of new information and the addition of new mobile devices in support of expanding capturing asset location information with GPS.
- Record Management Repositories:
  - This includes on-line systems that control and monitor the access and updates of digitized records and provide accessibility and document and record controls (governance).
  - Enbridge's Information Technology group is implementing a record management repository using a well-established software package from OpenText to provide for the storage of scanned documents and the functionality to access and maintain these documents.

These technologies are widely used throughout the industry. They have been selected because they meet current and evolving asset record management needs and are at a level of adoption where they can be cost effectively implemented at Enbridge.

The implementation of these technologies is most effective when applied to an entire class of assets, or the entire distribution system. Therefore each of these initiatives within the DRM Program represents a significant capital requirement.

The need for a Records Management System is a recent regulatory requirement for a formal integrity management program and the development of these systems, including the associated process and governance closely aligns with the DRM program. The MOP Program is described in separate evidence but because the principles of the DRM Program have been extended to the asset records related to MOP, the costs and work associated are included in the DRM program. In bringing together the records management aspects of these initiatives, care has been taken to align and coordinate these individual initiatives and ensure that consistent governance, standards, processes and technology are being utilized and that there is no duplication of activities or costs.

As stated earlier, the goal of the program is to generate asset records that are: verifiable, traceable, complete, accessible, accurate and timely. Although definitions vary, the definitions below capture the way that Enbridge uses these terms.

> Verifiable: This refers to the ability to verify that the record is a quality record, or that the information contained in the record can be verified by two or more non-conflicting records. For example, if the information on the record was captured by trained, authorized personnel that record would constitute a quality record.

Traceable: Traceability allows Enbridge to know what asset the information is linked to. For example knowing that information regarding the wall thickness of a pipe is linked to a specific section of a pipeline. Traceability is important not only to know what happened to the distribution asset (through a documented event history) but who changed a piece of information and why.

Complete: This refers to records which are marked as finalized, and have the requisite information required as of the date of creation. These are permanent records, not records 'in progress' or transitory in nature.

Accurate: This refers to knowing that the asset record is accurate as all analysis or decision making related to that asset will be based on the recorded information. For example, that the pipe was physically installed on the date recorded.

Accessible: This refers to information being easily available to the people that need the information. For example, if paper records are stored in a box, a person remote to that location cannot easily access those records.

Timely: This refers to the information being made available for use in a timeframe that is appropriate to support timely operational decision making. For example, it is important to have the information regarding a new main in the ground immediately after it has been installed.

The activities identified in Table 2 below have already been or will be commenced to address the program's goals and will continue over the next several years.

	Table 2: DRM Program Activities	Verifiable	Traceable	Complete	Accurate	Timely	Accessible
1	Ensuring critical paper records are accessible through digitization (including MOP scope)					X	X
2	Quality check of historic records to verify accuracy and expand completeness of information	X	X	X	X		
3	Utilization of GPS, barcodes and other similar technologies to ensure that assets are correctly recorded when installed	X	X	X	X	X	X
4	Utilization of 3D laser scanning and high definition video to provide a comprehensive and location accurate view of critical above ground assets	X	X	X	X	X	X

	Table 2: DRM Program Activities	Verifiable	Traceable	Complete	Accurate	Timely	Accessible
5	Implementation of records management technology to ensure that digitized records are verifiable, traceable and complete in terms of record management practices	X	X	X	X	X	X
6	Refine, enhance and enforce records related processes and standards in support of ensuring future records meet internal and external information requirements	X	X	X	X	X	X

	Table 2: DRM Program Activities	Verifiable	Traceable	Complete	Accurate	Timely	Accessible
7	Consolidate and improve access to asset condition information such that it can be used across departments for analytical purposes	X		X	X	X	X
8	As necessary, change technology in support of verifiable, traceable, complete, timely, accurate, and accessible records	X	X	X	X	X	X
9	Enhance measurement and feedback mechanisms to provide information regarding the success of the actions above	X	X	X	X	X	X

	Table 2: DRM Program Activities	Verifiable	Traceable	Complete	Accurate	Timely	Accessible
10	Clarification of accountabilities and governance structure to ensure adequate controls and ongoing visibility	X	X	X	X	X	X

Capital Requirements

The capital requirements are presented in Table 3 below. The DRM program costs have been organized by asset class with the exception of the utilization of GPS technology which will be applied to all asset classes and has been detailed separately as has the record management costs for MOP.

Table 3: DRM Capital Requirements ($000)

DESCRIPTION		Budget 2013		Forecast 2014		Forecast 2015		Forecast 2016	
DRM									
Pipeline	Digitization	$ 1,805		$ 500		$ 500		$ 450	
	Record Update: Header Conversion	$ 350		$ 350		$ 393		$ 127	
	Record Review & Update	$ 55		$ 140		$ 40		$ 40	
	Resurvey	$ 350		$ 750		$ 750		$ 750	
	Barcoding			$ 50		$ 100			
	Total Pipeline		**$ 2,560**		**$ 1,790**		**$ 1,783**		**$ 1,367**
Stations	Gate & District Stations	$ 2,700		$ 1,300					
	Sales Stations	$ 30		$ 2,070		$ 2,500		$ 2,000	
	Total Stations		**$ 2,730**		**$ 3,370**		**$ 2,500**		**$ 2,000**
GPS	Hardware	$ -		$ 500		$ 300		$ 300	
	Software	$ 700		$ 500		$ 200		$ 200	
	Field Resource	$ 2,300		$ 2,000		$ 2,500		$ 2,500	
	Total GPS		**$ 3,000**		**$ 3,000**		**$ 3,000**		**$ 3,000**
	TOTAL DRM		**$ 8,290**		**$ 8,160**		**$ 7,283**		**$ 6,367**
MOP	Records Management	$ 1,096		$ 1,479		$ 1,457		$ 1,328	
	TOTAL MOP		**$ 1,096**		**$ 1,479**		**$ 1,457**		**$ 1,328**
	GRAND TOTAL		**$ 9,386**		**$ 9,639**		**$ 8,740**		**$ 7,695**

Pipeline Records

Over the next several years, the majority of pipeline record activities fit into three categories:

- the digitization of paper records in order to preserve and / or make the information readily accessible to the field and office via the on-line record repository;

- the updating of priority records that are incomplete relative to current needs in terms of work and asset management practices;
- the resurvey of assets to validate and resolve location accuracy of a record that may be outdated as the land base features relative to which it was originally located have moved (e.g. through street widening or realignment), validates location information of conflicting records, and consolidates field information by creating new records. The creation of the new records enables; Locate Service Providers to be able to locate, survey and improve emergency response relative to Enbridge's underground infrastructure in an accurate and timely manner as required by legislation. In addition it allows internal business units to know the precise location and status of the Company's infrastructure and Records CADD Technicians to be able to accurately plot the infrastructure in a geographic information system (GIS).

  To ensure the newly created records do not become obsolete, GPS technology is being used to gather permanent information. The resurvey projects vary in size and location throughout the franchise area with varying complexities.

Focus for 2013:

Digitization:

- Miscellaneous work orders are old paper records that contain asset information and due to age, they are deteriorating and there is the potential for permanent loss of information. These tickets will be digitized and moved to an electronic records repository. There are approximately 1.1 million tickets. This effort started in 2012 and completes in 2013.
- Street service records contain information regarding service line installation. They contain information regarding the material, installed date, length of the service and possible inactive or cut-off information. The information on these

tickets is regularly accessed. By digitizing these records, this information will be available on field devices and in the office. There are approximately 100,000 legacy street service records to be digitized with 40,000 to be completed in 2013 and the remainder scheduled for 2014.

Record Update Priorities:

- The recorded information for some pipelines that are installed on private property will be updated. Approximately 1200 of these have been prioritized and the records will be updated to provide the requisite information. This involves paper review, visual review and at times a physical excavation. In order to manage costs, the work regarding pipelines installed on private property will be conducted over several years with remediation on a priority basis. In 2013, 350 will be updated with the remainder to be completed by 2016. This work will enhance the Company's ability to provide locates, survey the system and perform efficient emergency response as required.
- In addition, there are records related to services cut-off at main where the length and location of the remaining pipe is unclear. These records will be reviewed and the length and location updated. There are approximately 35,000 updates spanning 2013 through 2015 and beyond.
- The historical records for services for which pressure is reduced from high or extra high pressure to intermediate pressure, and then from intermediate pressure to inches water column (farm taps), do not contain complete location information. These records will be prioritized, reviewed and will potentially drive either a record update, or visual inspection and location update. The estimated number of services of priority is approximately 750. This activity spans 2013 and 2014.

Resurvey:

- The resurvey projects over the forecast period years will address known existing main pipeline resurvey projects and begin to address service resurveys and these activities will continue beyond 2016.

The focus for 2014:

Digitization:

- Continue digitization of remaining 60,000 street service tickets;
- Begin digitization of maintenance job cards. These are paper records that potentially contain information regarding changes to customer service locations (alterations), replace part or all of a service.

Record Update Priorities:

- Pipelines on private property: 350 to be updated in 2014;
- Farm tap updates;
- Engineering records standards will drive the review and potential updates to historic records: Installation dates; job cards; live stubs; liners inserts and casing information.
- Isolated steel services that enter a building underground are referred to as ‘Jumpers’. Historically this information has not been captured and is required to support integrity programs. There are approximately 21,500 historical records which require research and updating.

Resurvey:

- Continue prioritized resurveys.

Barcoding:

- Develop barcoding strategy, standards and procedures for pipeline assets. This effort spans 2014 and 2015.

Focus for 2015 and 2016:

Digitization:

- Continue digitization of maintenance job cards;
- Begin digitization of cut-off-at-main records. These are old paper records that contain asset information and due to age, they are deteriorating and there is the potential for permanent loss of information.

Record Update Priorities:

- Pipelines on private property to be completed: 520 to be updated in 2015 / 2016;
- Farm tap updates to be completed;
- Engineering records standards will drive the review and potential updates to historic records: construction job cards; as-built drawings; information on field notes.

Resurvey:

- Continue prioritized resurveys.

Barcoding:

- Continue barcoding activity - develop barcoding strategy, standards and procedures for pipeline assets.

<u>Station Records</u>

The activities for stations are a multiyear effort split between two streams of work:

1. Ensuring a complete and accurate set of asset records for 80 prioritized gate and district stations which are SCADA monitored (SCADA is a Supervisory Control and Data Acquisition system used to monitor remote equipment). Gate stations are defined as the pressure regulating stations where the custody of natural gas is transferred from transmission companies to Enbridge. District stations are

defined as pressure regulating stations located downstream of gate stations that further reduce natural gas pressure and feed lower pressure networks.

2. A second stream of work to address access to records for approximately 14,000 sales stations. Sales stations are defined as pressure regulating stations that reduce natural gas pressure and meter gas flow for delivery to customers.

Station records are not stored centrally; they typically reside within the business area where the particular work occurred. For all the above stations, asset records are to be located, gathered and digitized and the digital copy placed in a central repository where they can then be easily searched and made readily accessible.

For the 80 gate and district stations, these scanned records will be reviewed for completeness and accuracy of information. Where there are information inconsistencies, a visual field validation will occur and requisite records will be created and/or corrected. In addition, records will be enhanced utilizing technologies such as video, 3D laser scanning, and GPS to provide a more complete inventory of the station assets and their locations.

The focus for 2013 and 2014:

- 80 gate and district stations: locate, gather, digitize, verify the asset records, and make these records accessible via a central repository. In addition, work will commence to address record inconsistencies as well as to create the new types of records.
- 14,000 sales stations: These stations will be addressed on a priority basis. Work will commence to gather and digitize applicable asset records into a central repository. This work will be executed over time and the speed will vary based on resource availability. 2013 & 2014 target is 1,050.

Focus for 2015 and 2016:

- 14,000 sales stations: The work to gather and digitize applicable asset records into a central repository continues. Target is 1,250 for 2015; 1,000 for 2016.

GPS

Enbridge has established standards that will require the use of GPS to create the record of asset location. Over the course of the next 2-3 years, changes will be made to processes, technology will be upgraded, and training completed such that GPS data can be captured for new and existing assets. Over time, Enbridge will capture the location of all targeted assets with GPS. Enbridge's standard specifies that the accuracy of GPS units will be at least 10 cm and that the information will be consistent with existing note-keeping standards. Further the fact that the information is captured electronically reduces the potential for error and allows it to be shared on a near real-time basis. The accuracy and timeliness of this information has particular benefit to locators and is expected to reduce damages.

As locations are captured with GPS the accuracy of the information in the GIS system improves and it can be better used for spatial analysis, locates, emergency response and integrity survey compliance.

The work described below combines the opportunity to capture GPS data when an asset is visible (during construction or maintenance) with the need to proactively capture the GPS data for existing assets on a priority basis. With respect to the latter, GPS data will be captured for more than 1000 km of target mains and 20,000 valves (of which 6,000 are a priority).

Focus for 2013:

The focus in 2013 has been on establishing the processes and technology required to create as-built information from GPS data. This has required software upgrades to the

GPS units and the GIS system. Additionally, 12 field resources are capturing GPS data for existing assets when exposed by maintenance activities and are capturing GPS information for more 300 km of targeted mains and more than 2000 priority valves. Included in the costs are the contract costs to locate the targeted mains so that GPS data can be captured. In 2013 an additional area of focus is on the processes to manage and maintain the data that has been captured.

Focus for 2014:

Moving into 2014, the technology and processes will be further enhanced to capture the location information (service sketch and field note) related to the installation of gas services and the completion of maintenance work. An additional 50 GPS units will be purchased and the GIS software development will be extended to allow for the data from maintenance work and service installations to be captured and used effectively. Field resources will continue to capture location information for an additional 2000 priority valves and another 300 km of the targeted mains.

Focus for 2015 and 2016:

In 2015 and going forward, Enbridge will continue to capture and use GPS data as a standard for location information. In 2015, the work to capture the targeted mains and priority valves will be completed. When this work is completed, the work to collect GPS data for an additional 15,000 valves will be started as part of regular valve inspection programs. There will be minor software upgrades and the purchase of 30 additional units as their usage becomes broader in the company, and some units reach the end of their useful life. Field resources will continue to capture location information focusing on areas where previously captured GPS data indicates that a resurvey is required and where this information can be most valuable to other initiatives. For example, leak survey will be implementing a GIS based system for the recording of leaks against assets using GPS. For this to be effective, it is important that the assets are located correctly in the GIS system.

<u>MOP Record Management</u>

Focus for 2013:

In 2012, the program conducted a pilot MOP verification on approximately 500 km of Enbridge's highest pressure pipelines. In 2013, the focus is on standardizing the processes, governance, and technology by which the information is captured, stored, and managed so that it continues to be of value over the life of the asset. The nature of this work is labour-intensive and requires unique skillsets for interpreting records from multiple generations of documentation standards over time. Resources with these skillsets are in short supply, and with workforce retirements over time, such resources will be even more diluted. As such, it is expected that the improved records management practice will be applied to 550 km of the Company's mains in 2013.

Focus for 2014:

In 2014, the focus will be on completing the records investigations required for an additional 525 km of mains. The work will include the capture, storage, and management of these asset records such that they can be used in the verification of the MOP.

Focus for 2015 and beyond:

The program will continue with the same process at a pace of approximately 600 km per year through 2018 when it is expected that the MOP of all extra-high pressure pipelines will have been verified.

ENVISION EXTENSION

1. In April 2003, Enbridge entered into a multi-year capital project service agreement with Accenture to provide work and asset management services which supported the Company's construction, maintenance, and service activities. This agreement expires April 1, 2014. Enbridge expects to have WAMS Go-Live December 2015. In the interim period from April 2014 to the implementation of WAMS, Enbridge intends to extend the work and asset management services with Accenture and maintain the same Board approved treatment for these services from Settlement Agreement RP-2003-0203. Capital costs related to this extension are included in Integrity Capital as outlined in Table 1 below.

2. Enbridge is currently in negotiations with Accenture for the extension and any updates based on these negotiations will be provided when available. Enbridge believes that this will continue to maintain an effective solution in the short term. This approach also assists in reducing transitional and operational risks and will maintain the current level of work and asset management services through the transition period. Please refer to Exhibit B, Tab 2, Schedule 2 for more details related to the WAMS Program

Table 1:
Envision Extension Capital Cost Summary ($000)

	Budget		Forecast	
DESCRIPTION	2013	2014	2015	2016
Envision Extension	-	8,000	8,000	-

SYSTEM INTEGRITY AND RELIABILITY: DIRECT RESOURCE COSTS

1. The purpose of this evidence is to present the System Integrity and Reliability Direct Resource Costs capital requirements for the 2014, 2015 and 2016 forecast period.

Purpose and Scope of Direct Project Resource Costs

2. In recent years, the Company has operated with an increased focus on System Integrity and Reliability, which has increased the level of related activity and spending. From 2012 there has been recognition of a need for incremental resources being required to execute new and/or expanded programs and projects necessary to address identified System Integrity and Reliability requirements. The types of required skills and services provided through these resources include: distribution system related expertise; engineering expertise; project management oversight, planning and execution expertise; and other subject area expertise for specific programs and projects. These incremental resources are required to define, design, schedule and monitor the planning, implementation and execution of System Integrity and Reliability programs, many of which have several projects within their scope. The quality and effectiveness of the results of these programs would be negatively impacted without proper oversight. These resources may be contract workers, outside contractors, outside consultants or new employees. The Company leverages these resources where possible, to work on multiple System Integrity and Reliability initiatives, to maximize the efficiencies of these expenditures.

3. Additionally, the System Integrity and Reliability Direct Resource Costs include construction and service contractor costs that relate to work within the System Integrity and Reliability area. This relates to field execution work of the various

pipelines, services, stations and customer meter and regulator installation programs within the System Integrity and Reliability area.

4. As System Integrity and Reliability activity and spending requirements increased in recent years, Enbridge made the decision to include new capital costs related to System Integrity and Reliability within budgets for that area, rather than within more general Company-wide costs. This assists with understanding and evaluating the level of required spending in this area. System Integrity and Reliability Direct Resource Costs for the 2014, 2015 and 2016 forecast period are separate from the Department Labour Costs that are described in the Capital Overview Exhibit B2, Tab 1, Schedule 1.

<u>Direct Resource Capital Costs</u>

5. Table 1 provides the amount of Direct Project Resource Capital costs for each of the major System Integrity and Reliability business area cost categories for the years 2013 to 2016.

Table 1: System Integrity and Reliability – Direct Resource Capital Requirements ($000)

	Budget	Forecast		
Description	2013	2014	2015	2016
Incremental System Integrity and Reliability Resources	10,687	15,185	11,185	11,594
Construction and Service Contractor Fixed Costs	4,643	5,628	5,740	5,855
Totals	15,330	20,813	16,925	17,449

Witnesses: A. Mandyam
J. Sanders

Incremental System Integrity and Reliability Resources

5. Incremental System Integrity and Reliability Resource Costs were reflected differently within Enbridge's 2013 Budget. Within the 2013 System Integrity and Reliability Capital Budget, these costs were included within the categories of programs and activities (main replacements, service replacements, station replacements and upgrades and other), rather than within a standalone category of expense. The total amount of those costs within the 2013 System Integrity and Reliability Budget is $15.33 million.

6. The increase from 2013 to 2014 ($4.5 million) arises for several reasons. First, it represents full-year costs to have resources in place to accommodate expected increases in Safety Integrity and Reliability activity levels in the coming years. Second, it represents resources anticipated during the study and early phases of planned System Integrity and Reliability programs. Finally, it takes account of the fact that the actual level of spending for these resources in 2013 is expected to be significantly higher than the budget level for this category of spending within the $387 million overall Board-approved capital budget.

7. There is a decrease in this category of costs over 2015 and 2016 (approximately $4 million per year less than 2014). That takes into account the expectation that many of the System Integrity and Reliability studies will be complete, and programs will be underway.

Construction and Service Contractor Fixed Costs

9. Construction and Service Contractor Fixed Costs represents an allocation of the total fixed costs that the Company is required to pay under its services agreement with its current construction and service contractors. This allocation within the

System Integrity and Reliability Direct Costs category represents the proportional third party construction activity requirements in this area (as compared to the requirements across the entire utility). The changes in the level of these costs each year is largely a function of the expected relative level of work requirement within the System Integrity and Reliability area as compared to the rest of the utility.

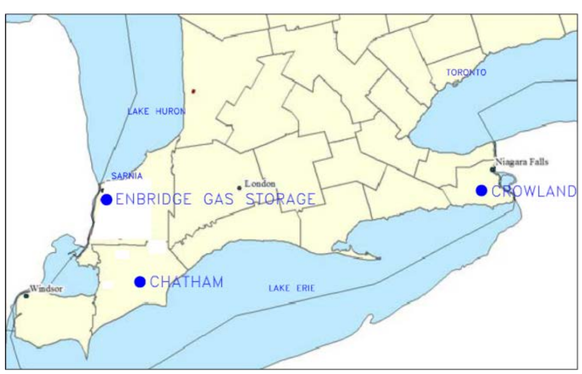
CAPITAL BUSINESS AREA - STORAGE

1. The purpose of this evidence is to present the Enbridge Gas Distribution ("Enbridge", "EGD" or the "Company") Gas Storage capital expenditures forecast for the 2014, 2015 and 2016 fiscal years. This exhibit provides the Ontario Energy Board (the "Board") with a detailed breakdown and explanation of the various categories of capital expenditure spends and justification for planned major projects over $2 million.

Description of Enbridge Gas Storage

2. Enbridge Gas Distribution's Gas Storage Operations Group, located in Lambton and Kent Counties, is responsible for the design, construction, operation and maintenance of all the Company's above and below ground gas storage facilities. The Lambton/Kent facilities are separated, both geographically, and operationally, from the distribution operations of EGD. This group also operates a small storage pool, the Crowland Storage facility, within the Company's distribution franchise in Niagara Region. Figure 1 below shows the general location of Enbridge's Gas Storage Operations in Lambton and Kent counties and the Crowland facility.

Figure 1: Gas Storage Location



3. Enbridge Gas Storage Operations stores up to 112 Bcf of natural gas in 11 storage pools and can deliver 2.5 Bcf/d through three pipelines that interconnect with the transmission system owned by Union Gas Limited and one that interconnects with the Vector Pipeline.

4. Of this total storage capacity, about 6.7 Bcf is operated by Enbridge on behalf of Union Gas, and 14 Bcf is unregulated storage. The unregulated storage capacity has been created since the Board's "NGEIR" Decision in 2007.

5. The underground storage of natural gas is an integral component of Enbridge's gas supply and distribution infrastructure. It provides much of the logistical capacity that the Company requires to balance the seasonal and daily differences between its gas supply and gas demand requirements. Underground storage uses previously depleted oil and gas production reservoirs which are then equipped with wells and a volume of cushion or 'base' gas that are necessary to optimize the capability of the reservoirs for gas injections and withdrawal. These developed reservoirs are then connected into an appropriately designed pipeline gathering network and compressor plant infrastructure to provide the designed levels of daily gas flow and inventory capacity.

6. Capital Spending for Gas Storage Operations over the 2014 to 2016 period is forecast to decline from the levels that have been seen in recent years. Storage capital spending is set at $19.2 million in 2014 declining to $13.8 and $8.9 million through 2015 and 2016 respectively.

7. The recent spends have reflected the completion of several larger projects that will improve the overall integrity and reliability of both surface and sub-surface assets

(gas measurement, Sombra Station by-pass, seismic program) and which have been required to ensure compliance with technical standards (stack and noise emissions, engine upgrades).

8. The capital spend in the forecast period will continue to include projects of this nature (well integrity, compressor plant upgrades and the construction of a new building to allow for the relocation of staff); however, it will see the magnitude of those costs decline as those projects and programs come to an end. The attached Table 1 identifies the Company's forecast capital spending on Storage Operations for the 2014 to 2016 period, as well as the 2013 budget. This chart identifies capital programs or projects over the 2014 through 2016 period with a spend greater than two million dollars, as well as areas of other required spending.

Table 1: Gas Storage Capital Summary ($000)

	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Corunna Compressor Plan	1,500	9,680	4,620	-
MOE C of A	7,320	3,000	-	-
Well Integrity	2,838	2,530	4,800	5,760
Observation Wells	1,890	18,50	2,450	1,600
Other Projects < $2M	5,557	2,108	1,938	1,550
Total	19,105	19,168	13,808	8,910

9. The following discussion will provide an overview of these programs over the forecast period. A more detailed discussion is set out in the Attachments to this evidence.

Witnesses: D. Dalpe
B. Pilon

10. There are a number of projects included in the upgrades to the Corunna Compressor Station that are intended to improve the safety and reliability of Storage Operations. The largest is for the construction of a new building to replace and relocate the occupied 'people spaces' at the Corunna Compressor Station to a new location that is at a safe distance from the compressor plant. These workspaces include the current Administration Offices, the Control Room, the Mechanical and Instrumentation shop areas and it will also provide a workplace for the Warehouse staff. Enbridge has chosen to conduct this work based upon the findings and recommendations of the Baker 'consequence' study that was completed for the Station. This study was filed as Exhibit I, Issue B4, Schedule 1.2 in the evidence for EB-2011-0354. The indicated costs also include work to improve security at the Station, to relocate compressor oil storage and to pipe water to a number of locations at the site for fire-fighting needs, if required.

11. Another Corunna Compressor Station project, also linked to the findings of the Baker consequence report, is the replacement of one of the Motor Control Centres (MCC #1) in 2015. This project includes the cost to replace equipment and the construction of a new building in which to contain it. The existing facility was installed many years ago and, for a number of reasons, is now not of a capacity or reliability to provide the service and redundancy required of it. Among those reasons are the age and layout of the equipment within the MCC, as well as the location and structural design of the current MCC building itself. It was not built to the capacity or the design standard that is required of it today and the Baker consequence report has identified it as an operational risk in the event of a plant failure.

12. There is a more complete discussion of these safety and reliability improvements to the Corunna Compressor Plant set out in Attachment “1”.

13. In addition to the safety and reliability work at the Corunna Compressor Station, 2014 will also see costs related to the final elements of the noise and exhaust emission compliance work that has been underway since 2012 to address issues raised by the Ministry of Environment (MOE). This project is described in Attachment “2”.

14. Enbridge also has a number of activities that make up a Well Integrity program. These include a well testing program, a well casing and wellhead replacement program and a well drilling program intended to replace well flow capacity that has been lost to well re-lines and well abandonments in recent years.

15. In recent years, the Company has been conducting a program to pressure test its storage wells, to determine whether the wells have the ability to deal with the gas pressures required of them. Enbridge’s unregulated storage business had completed such a program on the wells in four of the storage pools in anticipation of the pressure elevation, or ‘delta pressuring’ of the pools. Because of the results of that earlier work, Enbridge has determined that the wells in the remaining pools (none of which are being ‘delta pressured’) should also be tested to ensure their integrity and that it would also replace some of the wellheads, where necessary, to bring them up to current government standards (CSA Z341 Standard – Storage of Hydrocarbons in Underground Formations).

16. Although the older wells and wellheads have been grandfathered, many do not meet this current CSA Z341 Standard. Over the nearly fifty years of Enbridge’s

storage operations, wells have been drilled and equipped with wellheads of a variety of configurations. Some of those wellheads provide only one entry point into the well; others have threaded, rather than welded, connections. Because of the technical work required to prepare a well for pressure testing, it is seen as a good opportunity to replace these wellheads and avoid that preparation cost at some other point.

17. The well casing/wellhead replacement program is the follow up work that can result from Enbridge's ongoing well casing inspection program. These inspections are required of a storage operator in order to comply with the CSA Z341 Standard (Storage of Hydrocarbons in Underground Formations), as adopted by the Ministry of Natural Resources. The wells that have a corrosion problem must have their casing either replaced or re-lined, where it is possible; where it is not possible the well will be abandoned. This program has been underway since the mid-1990s.

18. The last element of the well integrity work is the forecast drilling of a replacement injection/withdrawal well in each of 2015 and 2016. Most of the existing injection/ withdrawal wells are in the order of 40 years old, and as some of these are abandoned over time, their capacity will need to be replaced. These two wells are intended to begin to replace some of the lost injection/withdrawal capacity.

19. The wells will be drilled using horizontal drilling technology. This is part of a longer term strategy to eventually replace most of the existing vertical wells with horizontal wells. Horizontal wells are more cost effective than vertical wells and they offer the Company the opportunity to locate wellheads and related pipeline facilities more strategically for the benefit of both the landowners and Enbridge. The indicated

cost of this program in Table 1 also includes the piping costs that are required to connect the wells into the existing gathering pipeline system.

20. Attachment “3” provides more information about these three elements of the well integrity activities.

21. In recent years Enbridge has been conducting a number of activities (seismic program, observation well drilling and reservoir modeling) intended to improve its understanding of its storage reservoirs and, ultimately, of its gas inventories. The last of the higher cost programs included in the 2014 through 2016 period is for the drilling of a number of observation wells in areas adjacent to its storage reservoirs. The drilling of observation wells is a follow up to earlier seismic program work and is intended to confirm the limits of the reef boundary and the presence of any associated rock zones that have porosity and permeability. These observation wells will help Enbridge to determine the physical extent of these zones and if they are in communication with the pools.

22. The information gained from these wells will also help Enbridge to confirm if the current boundaries of the Designated Storage Areas (“DSAs”) are adequate to protect the pools. It is expected that two observation wells will be drilled in each year of the IR forecast period and possibly two others after that. The cost shown for this program also includes an amount for the acquisition of additional land rights that would be required to enlarge or change the DSA boundaries. There is more information about this drilling and pool integrity work included in Attachment “4”.

23. Although the above mentioned projects account for most of the spend in each year of the forecast period, there is an additional amount under ‘Other Projects’ for each

year that range from $1.5 million to $2.0 million annually. These are the smaller cost, and in most cases, more routine capital projects in Gas Storage. Among them are longer term maintenance capital activities such as acid stimulations of wells and overhauls of engine and compressor. And during the forecast period there is also a number of smaller projects related to asset documentation and plant control and automation improvements. Table 2 below lists the relatively larger projects making up those costs.

Table 2

	2014	2015	2016
Warehouse Racking/Layout Change		150	
Well Acid Program	300		325
Wellhead Emergency Shut Down	125	125	
Pipeline Specifications Standard	100	100	100
Pipeline Integrity Records	150		
Drawing Upgrades	100	100	100
Compressor Engine Overhaul	250	250	500
Compressor Overhaul	100	225	100
Crowland Plant Upgrades	200	200	
Gas Chromatograph at Chatham D		400	
Remote Plant Operation Control	350		
Miscellaneous	433	388	425
Total Other Projects	$ 2,108	$ 1,938	$ 1,550

<u>Productivity</u>

24. Although much of the planned project work described above is focused mainly on maintaining the integrity and reliability of Enbridge's storage operation, there are several planned activities that will also provide greater efficiency and productivity gains. The best examples are some of those related to the storage well integrity program. For example:

   a. The wellhead and well casing replacement projects extend the useful life of existing wells beyond that originally expected, and avoid costs of drilling new wells;.
   b. an acid stimulation program that is conducted on gas injection/withdrawal wells revitalizes these wells to near, original flow characteristics. It is conducted on wells whose performance has declined as a result of 'damage' that is caused by formation fluids, and other contaminants, that are naturally produced from the storage reservoirs; and
   c. the replacement well drilling program, using horizontal drilling technology, will provide long term economies in terms of both the lower effective capital cost of replacing wells that have reached the end of their useful lives, and in the reduced life-cycle O&M costs (logging, pressure testing, surface rents, laneway maintenance) that will result from having a significantly reduced number of wells. This will drive cost savings as compared to the vertical wells that have historically been used.

Witnesses: D. Dalpe
B. Pilon

CORUNNA COMPRESSOR STATION

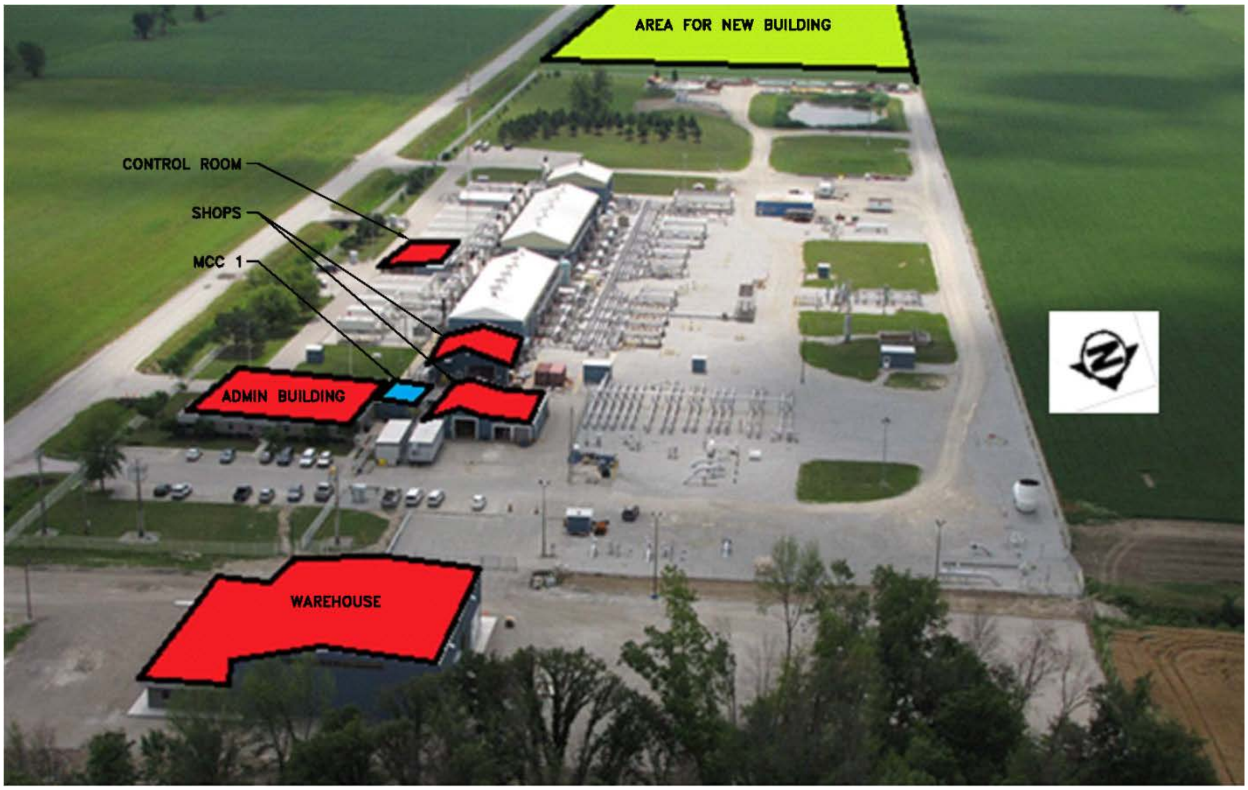
SAFETY AND RELIABILITY IMPROVEMENTS

PROJECT SUMMARY

Enbridge has determined that, because of the layout and construction of its main plant, the Corunna Compressor Station, there is an unacceptable level of risk to the safety of its staff and contractors, and to its overall operational reliability. This program is intended to relocate the workspaces that are regularly occupied by workers at the site and to make changes to the location and structural design of another building containing critical equipment, as well as the equipment itself.

All of the occupied workspaces at the Corunna Compressor Station are currently located too close to the plant and related piping. As a consequence, if an equipment failure were to occur at the site, with a subsequent release and ignition of gas, the outcome would be catastrophic. The Company has determined that it must take steps to mitigate the associated risks to staff safety and to the reliability of Gas Storage Operations generally. The largest part of this program will see the construction of a new building to accommodate those staff currently working in the Administration Office, the Control Room, both the Mechanical and Instrumentation shops and the Warehouse. Those workspaces are highlighted in red in the aerial photograph of the Corunna Station in Figure 1 on the following page.

Figure 1



Enbridge also intends to replace one of the Motor Control Centres (MCC #1) at the Corunna Compressor Station. This will require the construction of a new building, and the installation of new, upgraded equipment to replace the outdated equipment that exists in the existing MCC #1. An MCC is a hub of all of the electrical and control wiring, and related switch-gear equipment, required for plant operations, much like the electrical service panel in a typical home, but it is much larger and more complex.

In addition to the current MCC building being in a location, and of a structural design, that makes it very vulnerable to the effects of an explosion in the adjacent compressor buildings, the building and equipment are also of an age that have rendered it undersized, obsolete and out of compliance with the design standards that would be used by industry today for such a facility. This building is highlighted in blue on Figure 1 above.

Both of these new buildings will be located and/or constructed so as to mitigate the risks that have been identified with the current buildings. The new Administration and Control Room building will be located on Enbridge owned property that is at the Southern boundary of the plant site. This area is highlighted in green on the aerial photograph, Figure 1, above. The replacement for MCC #1 will remain near the compressor buildings, but will be designed and constructed so as to be able to withstand the blast impulse that would result from an explosive event. Both locations will allow effective on-going storage operations and an acceptable business resumption plan.

The cost estimates for both of these projects are based upon estimated building sizes, current construction cost benchmarks and equipment cost estimates.

The Administration/ Control Building cost is estimated at approximately $13 million based upon a total building size of about 42,000 square feet. The estimates for the entire project, which total approximately $13.5 million, include the cost of a number of other site security projects such as added fencing, firefighting infra-structure and the relocation of oil tanks.

The cost of the MCC replacement is forecast at $2.3 million, which is largely driven by the cost of the equipment contained therein.

A BUILDING REPLACEMENT PROJECT

DESCRIPTION OF WORK

This project will see the construction of a new building to accommodate the various Gas Storage Operations work groups at the Corunna Compressor Station. This building will replace the current Control Room, Administration Building and Mechanical/Instrumentation Shop. It will also include a workspace for the Warehouse and Procurement staff as well as some additional Warehouse space.

Enbridge had conducted a study to identify the consequences of a plant equipment failure scenario, in which there would be a release of gas and subsequent ignition. The findings of this study had determined that the current work spaces, and their human occupants, would be seriously affected by such an event. The new building will be designed and located so as to meet current Standards and Codes and to ensure that such an event would not jeopardize staff and would not compound the disruption of operations or impede business resumption.

To this point Enbridge has engaged the assistance of its Facilities group and an architectural/engineering firm to help to develop the scope of the project and to design and locate the building. In identifying a suitable location for the new building, Enbridge had to recognize not only the proximity to the compressor plant, and the implications identified in the consequence report, but also the proximity of the new building from high pressure pipelines. Fortunately such a location could be found on lands already owned by Enbridge.

The completion of the design work and acquisition of the necessary municipal and environmental approvals, are expected by the end of 2013. Construction is expected to begin early in 2014 and will continue into mid-2015 for completion.

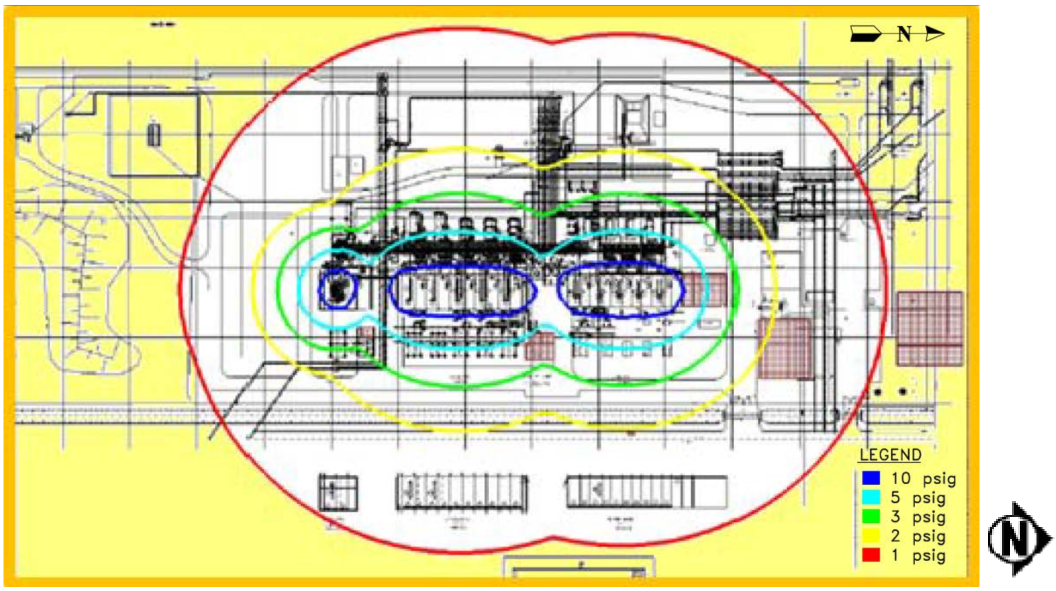
NEED – BUILDING REPLACEMENT

The layout of the Corunna Compressor Station was created at the time of the commencement of gas storage operations in the early 1960s. It reflects the scale of the storage plant at that time and, more importantly, the industry's design practices then as they related to staff safety and operational security. Since that time there have been many changes at this plant site as a result of the growth in the operation, and of changes in industry practices as they relate to site layout. For example, since 1998 the TSSA has required that new compressor installations be at least 100 meters from any buildings that are intended for human occupancy. Most of the current workspaces at the station are within 50 meters of existing compressor plant.

In view of this, Enbridge commissioned a study of its Corunna Compressor Station in 2011, to determine the consequences of a gas release and explosion there. The study was completed by Baker Engineering and Risk Consultants Inc. ("Baker") of Burlington Ontario. In its findings it outlined the implications for staff safety as well as for the reliability and security of storage operations generally. Baker also offered a number of suggestions that would reduce or eliminate the consequences of such a plant failure. These included the movement of the various work spaces away from the plant, the decommissioning of specific equipment and the fortification of buildings to withstand the pressure wave that would emanate from an explosive event.

Figure 2

Blast Overpressure Zone Contours



The above graphic, Figure 2, is taken from the Baker consequence report. It has been modified only to make it more legible. It is a depiction of the Corunna Compressor Station showing the magnitude and location of pressure waves that would result from an explosion in the compressor buildings. These pressures range from a high of 10 pounds per square inch in theinner, dark blue contour to 1 pound per square inch in the red contour. Although these pressures may not seem exceedingly high, they are well in excess of what a typical building is designed to withstand. The buildings, equipment and staff located within these 'overpressure zones' would be seriously impacted by a blast impulse.

Figure 3, below, is an aerial photograph of the Station but edited to show these same overpressure wave contours. It is included to provide a clearer image of the plant site and the areas and buildings that would be affected.

Figure 3

In the absence of specific requirements that set out the distances that occupied workspaces should be from facilities like the Corunna Compressor plant, Enbridge has used the overpressure information, provided in the Baker consequence report. However, because the scope of the Baker study had not included the consequences of a pipeline rupture, and the heat or thermal radiation that would emanate from it, Enbridge has also factored in industry guidelines regarding the effects of thermal radiation, as it has considered the implications of the Baker consequence report.

The heat affected, or thermal-radiation zone, is determined by calculating a "Potential Impact Radius" ("PIR") for each of the larger pipelines at the site. It takes into account the diameter of each of the pipelines and their maximum operating pressures ("MOP"). The original research of this PIR was conducted by the Gas Research Institute ("GRI") but has subsequently been adopted by the TSSA in its most recent Code document. Based upon the size and pressure of Enbridge's gas storage pipelines, the heat affected area at the Corunna Compressor Station is calculated to be anywhere within 200 meters of them.

Ensuring the protection of these workspaces, and the staff within them, is critical to Enbridge. Apart from its fundamental obligation to provide staff with a safe work environment, it also ensures a greater reliability of its Gas Storage Operations and, thereby, the security and wellbeing of gas distribution operations for its gas customers.

An example of this current workspace problem is in the location of the Control Room and its occupant, the Operations Group, in Gas Storage. This group is responsible for all of the day to day storage operations as well as communications with upstream and downstream partners. The Control Room is staffed and operated, 24 hours a day, every day of the year. Storage Operations cannot function without this group, their equipment and their workspace, being fully operational. The Control Room location

is now positioned in a very sensitive area, between the two main compressor buildings, and within 30 meters of each. It is a convenient location from which to operate the plant, but is among those areas that would be most exposed to the full brunt of an explosion event in the plant. Even a limited failure and fire could render the Control Room useless. There is a similar story for the other occupied workspaces at the site.

In addition to the matters related to the safety and security of Gas Storage Operations, there is also an accommodation need that the existing buildings do not provide for. The capacity of the Administration Building has been a constraint for a number of years and has reached the point where some expansion is required. However, the locations of pipelines, and other equipment near the building, have made it impossible to make any structural changes to the building that that could help to relieve these space pressures.

Similarly, even though warehouse space had been added in 2008, there remains a need for more space to accommodate materials that are currently stored at a number of remote sites. One of these is a rented space, and is about 10 kilometers from the plant; others are in old barns and other vacated buildings, approximately 4 kilometers from the plant. They are unheated, infested by vermin and at the end of their useful life. For these reasons these spaces are difficult to manage and are felt to compromise both the efficiency and security of Gas Storage Operations.

So, in addition to the improvements to worker safety that this project will bring, it will also provide a long term solution for these accommodation needs.

SITE CHANGES CONSIDERED

The Baker consequence report had identified several high level strategies that Enbridge might follow to mitigate the safety hazards to the 50 to 60 staff and contractors working at the site. As Enbridge considered these it also incorporated the implications of the PIR, or thermal radiation zone, in determining the alternatives available. Among them were:

a. Do nothing. Although this was not a recommendation of the Baker report, it is an alternative available to Enbridge. However, the Company does not accept the risks associated with choosing this alternative.

b. Make site layout, building structure and equipment changes at the site to protect staff. This would require the fortification of many of the occupied buildings at the site, changes to compressor building and/or the decommissioning of some of the compressor units to mitigate the blast overpressure. This would be a costly solution and would do nothing to deal with the risks and consequences associated with the thermal radiation zone.

c. Relocate work-spaces and staff away from the blast and thermal radiation zones.

The Company determined that, to protect staff, it would make the changes as identified in Option c. That is, it would make a fundamental change to the location of these occupied work spaces. This option is the most effective in protecting staff and also the lowest cost. Apart from the staff safety matter, Enbridge also intends to fortify some of the other ‘at risk’ structures that contain critical infrastructure and where it was not practical to move them. This building construction project is specifically related to Option c.

Building Options

The determination of the scope of the project began with two steps. First, a number of building alternatives were identified that could provide the work spaces required. All of these alternatives included the continued use of some of the existing buildings where it was possible. Secondly, a 'needs' matrix was created that incorporated the intended safety, operating, people and 'other' objectives. In the matrix, the operating, people and other objectives were scored from 1 to 5; the safety objectives, however, were scored with either a 'pass' or 'fail'. This matrix was then used to 'score' each of the alternatives. A copy of the matrix is attached to this document as Appendix 1

Because employee safety was scored as either a 'pass' or 'fail' in the matrix, it resulted in the immediate elimination of two of the alternatives. Options 2 and 3 both included the continued occupation of the warehouse building at the North end of the plant site. Option 2 assumed the expansion and fortification of that building to accommodate all occupied workspaces, whereas Option 3 would have left it only as a warehouse but required the construction of a second building at the South end of the plant site to accommodate the Administration office needs, the Control Room and the Mechanical and Instrumentation staff. Both of these would have mitigated the consequences identified in the Baker report but neither would have resulted in the movement of staff away from the thermal radiation zone; as a result both were disqualified.

Of the two remaining options, Option 4 scored marginally higher than Option 1. Enbridge then considered these two options in greater detail based upon other, more qualitative criteria such as employee satisfaction, operational effectiveness and cost.

Option 1 would have included the expansion of the current warehouse building so that it would accommodate the Maintenance and Instrumentation shops. In addition, this option included the construction of a new Control Room building at a safe distance from the Compressor Plant and either the construction or purchase of a new office building away from the plant site, possibly as far as 5 to 10 kilometers. Because this option required the construction of one building, the expansion of another and the construction or purchase of a third building, it was estimated to cost as much as 20 percent more than would Option 4. Also, it does not provide all of the safety improvements that Option 4 does.

The aerial photographs of the plant site, shown below and on the next page, show the location of current workspaces (Figure 4), as well as the generalities of Option 1 (Figure 5) and Option 4 (Figure 6). In all cases, North is to the right.

Figure 4

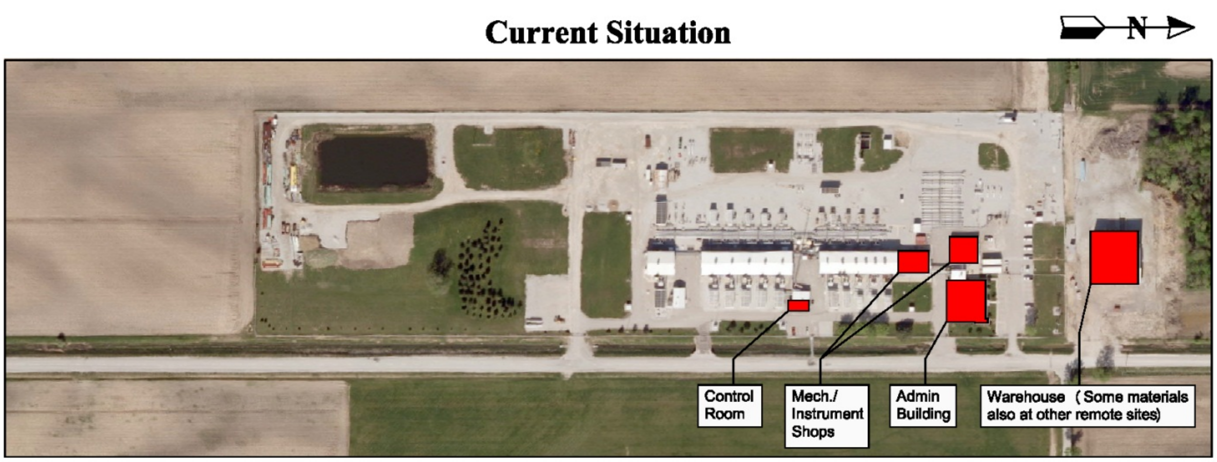


Figure 5

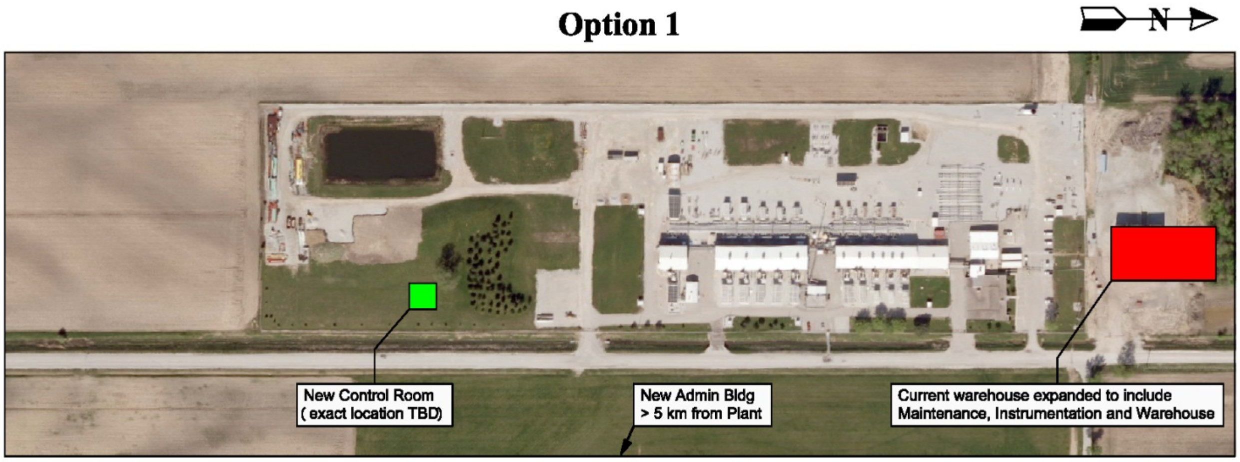


Figure 6

Of these two, Option 4 (Figure 6) is the preferred alternative. It will result in the construction of a new building at the South end of the plant site, in a location that is outside of both the overpressure and thermal radiation zones. The building will be of a design and construction that will reflect its purpose as a field operations facility. It will not be elaborate; it will be practical, functional and relatively easy to maintain.

Upon completion of this project, the current Administration building, Control Room and Mechanical and Instrumentation shops will be demolished. The current warehouse will continue to be used for warehousing however it will not be occupied as a full-time working location. It will be serviced and operated from the new building. The continued use of this existing warehouse space, when combined with the additional warehouse space that is planned, will allow Enbridge to discontinue the use of the rented warehouse space and to demolish the remote barns.

COSTS

The total forecast cost of the building replacement project is $13.5 million.

This building will be appropriately constructed as a working, multi-function field office; it will not be extravagant in either its design or its décor. It will be a practical workspace for field staff involved in construction and operational activities, and will provide a businesslike workspace for those with more office-oriented, work duties.

The cost estimate for this project is based on the need for approximately 25,000 square feet for the office and Control Room and approximately 19,000 square feet required for shop/warehouse space. Based upon standard construction costs for these two types of construction of $250 and $150 per square foot respectively, the construction cost of this building is estimated at approximately $9 million. These construction costs have been provided by the Enbridge Facilities group and a third-party architectural firm, Walter Fedy.

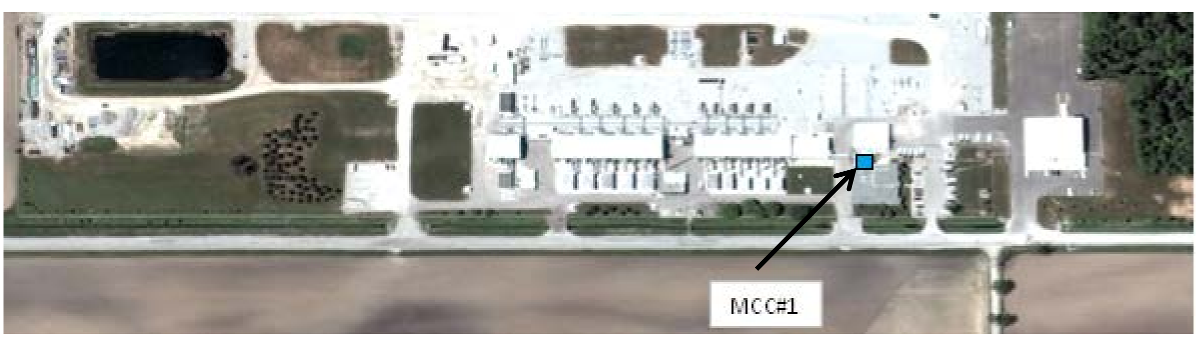
The balance of the $13.5 million forecast cost for the new building project relates to site preparation costs ($250,000), architectural, engineering and project management services for the construction project ($1 million), the cost of a number of other site security projects, such as added fencing, firefighting infra-structure and the relocation of oil tanks ($500,000), IT infrastructure and furniture ($850,000) and contingency ($2 million).

B MCC #1 REPLACEMENT

DESCRIPTION OF WORK

This project will include the construction of a new building and the replacement of the equipment in the existing Motor Control Centre (MCC) #1 at the Corunna Compressor Station. The new MCC will be larger so as to allow a layout with appropriate equipment separation and it will be constructed so as to be better able to withstand a plant explosion. The aerial photograph below again shows the plant site and the current location of MCC#1.

Figure 7



The current MCC#1 is a metal clad building housing one of three electrical sub-stations for the plant. It contains a natural gas fueled boiler that provides heat for process and domestic use and a 250 kilowatt gas fired APU (generator), which is used to back up the electric power supply to MCC#1. This generator is not, however, of a large enough capacity to provide a redundant backup power to the electric switch gear and infrastructure of the entire plant.

The new MCC will be built on a site near the North end of the Compressor Building #1, and to the Southeast of the current location. Because of the close proximity to the plant, the new building will have to be constructed to withstand the pressure wave that a plant failure would produce, as anticipated in the Baker consequence study. Much of the complexity of the project results from the need to build this facility while still using the existing MCC. In 2015 there will need to be a scheduled outage to conduct a ‘cutover’ to the new equipment, and to decommission the old facility.

The engineering, planning and procurement for this project will begin in 2014 with construction and commissioning planned for 2015.

NEED – MCC #1 REPLACEMENT

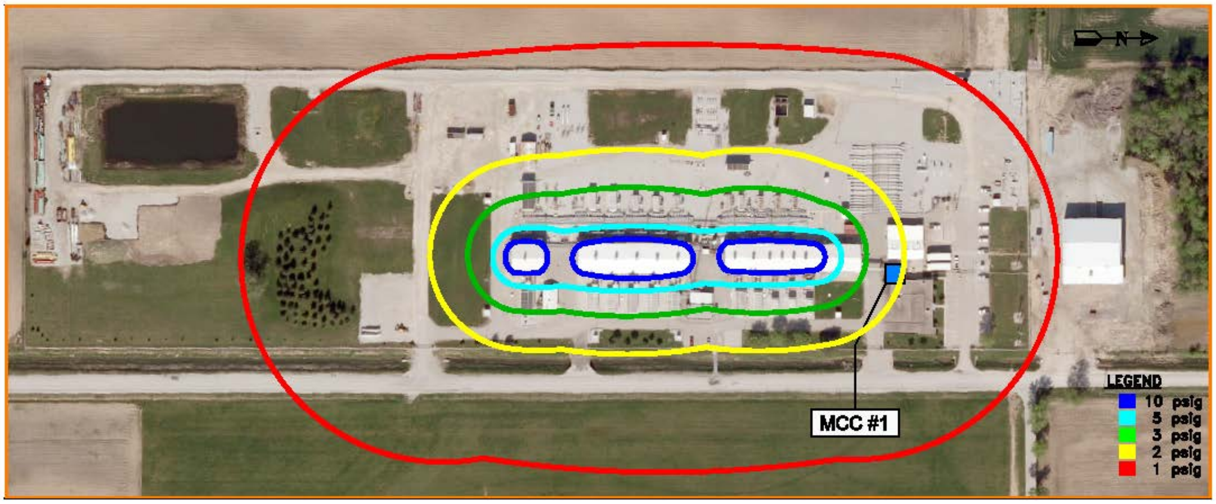
The need to conduct an upgrade to MCC#1 has been under consideration for several years, mainly in recognition of the age and capacity of the equipment in it. However, since receiving the Baker consequence report in 2011, Enbridge has become aware of the added concern with the location of MCC#1 and the level of risk that it brings to the reliability of the Corunna Compressor Station and of Enbridge’s storage operations generally.

Prior to being made aware of the concerns raised in the Baker consequence report, Enbridge had completed an engineering study of the existing MCC. Enbridge had engaged a consultant; Collins-Ferrera Engineering Inc. (Collins-Ferrera) to conduct a study of MCC#1 to determine the risks that were inherent in the age and, more importantly, the layout of the current equipment within it, and to make recommendations to mitigate them. Collins-Ferrera had recommended that the three major pieces of equipment located in MCC#1 should be replaced and that the building should be upgraded to improve ventilation and to provide for the physical separation of the electrical and mechanical equipment. Much of the concern expressed in the report was with the age and/or capacity of the equipment and the recognition that the building would require modifications.

Later, the Baker consequence report took a broader look at the Station layout and, among other things, at the consequences that an explosion in the plant might have for critical equipment, such as that contained in the MCC#1. Among its findings the Baker consequence report highlighted the risk that the location and structural integrity of the current MCC#1 would likely bring to Gas Storage Operations. The combination of these two reports served to increase the priority of replacing MCC#1 as soon as possible.

Figure 8, below, depicts the plant layout and overpressure zones of the Corunna Compressor Station, as taken from the Baker consequence report, and has been altered to show the location of the MCC#1. The Baker study found it to be in one of the areas that would be most affected by the pressure impulse wave that would result from an equipment failure in the plant. In the event of a plant equipment failure, it would be lost or seriously damaged, and would likely be among the causes of an interruption to Gas Storage operations. And in addition to the initial interruption, the time and technical effort required to recover Gas Storage Operations would be considerably greater as the damaged MCC#1 would first have to be demolished and replaced.

Figure 8



In its recommendations, the Collins-Ferrera report of April 2011 stated "…it seems that a total replacement of MCC#1 is inevitable". It had recommended that all of the equipment, except for the electrical switchgear, should be replaced immediately as that equipment posed a risk to both the safety and reliability of the plant. At the time of the report all of the equipment had reached or surpassed its reasonable life expectancy, with the boiler being at least 15 years beyond what Collins-Ferrera felt industry should expect of it. In all cases, Collins Ferrera felt that the age of the equipment made it difficult to get parts and service.

In addition to these problems there is also a problem with the lack of generator capacity to provide the redundancy desired for the plant, should the only other backup generator be out of service. And lastly, though not a Code problem, the current building size and layout do not offer the separation of equipment in the building that would be considered as Industry Standard.

Figure 9

The photograph in Figure 9, to the right, illustrates the Collins-Ferrera concern with the layout of, and lack of separation between, electrical and gas fired equipment.

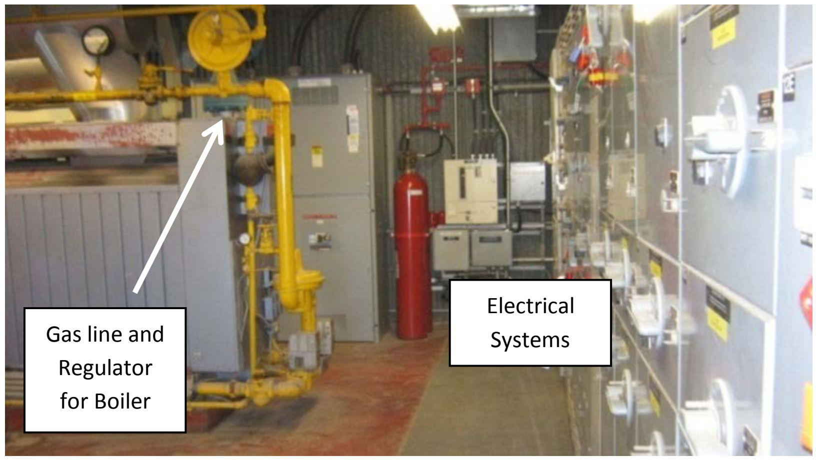


Figure 10

The picture to the left (Figure 10) is of MCC#1 from another perspective, from a position behind the boiler. The gas fueled generator is located on the far side of the boiler but, again, is quite close to the electrical equipment and with minimal physical separation.

This project is driven by shortcomings in the design, location and vintage of an asset that has been in place for many years. The equipment capacity upgrades are needed only to provide the redundancy required of the plant; it does not add gas storage or flow capacity.

COSTS

The total forecast cost of the MCC#1 building replacement project is $2.3 million.

The Collins-Ferrera report of 2010 included a cost estimate for the larger equipment components of this project at just over $1 million. This covered the cost of acquiring and installing the generator, boiler and motor control equipment but did not include any of the ancillary equipment and infra-structure that will be required (smoke and fire alarms, fire suppression, ventilation). It also did not cover the cost of construction of a new MCC building, designed to withstand the pressure impulse wave that would result from a plant equipment failure as envisaged in the Baker consequence report.

Enbridge has updated the Collins-Ferrera 2010 cost estimate for inflation and to take into account of the costs of constructing a new building. The cost of the equipment is now forecast at $1.3 million. The additional costs include the forecast $1 million expense of constructing a new building (which must be well-fortified because of its proximity to the compressors) as well as a $300,000 expense in 2014 for the engineering work for this project.

Appendix "1"

		Criteria	Responsibe for Rating	Scoring Criteria	Weight	OPTION 1		OPTION 2		OPTION 3		OPTION 4	
						WH : Onsite Ops : Onsite CR : Onsite Admin Bldg: Offsite (> 5Km)		WH : Onsite Ops : Onsite CR : Onsite Admin Bldg : Onsite (single facility)		WH : Onsite (N) Ops : Onsite (S) CR : Onsite (S) Admin Bldg : Onsite (S)		WH : < 1Km away Ops : < 1Km away CR : < 1Km away Admin Bldg : < 1Km away	
						Expand current warehouse to accomodate Operations. New Control Room at south end of site. Admin building offsite		Expand current warehouse to accommodate operations, control room and admin staff		Warehouse to accommodate warehouse only. Operations, control room and admin move to new building on south end of property		New Building to incorporate all functions currently at Tecumseh (incl. warehouse). Existing w/h modified for another function (storage?)	
						5 - significantly exceeds criteria, 4 - exceeds criteria, 3 - meets criteria, 2 - does not meet criteria, 1 - below criteria							
						Comments	Score	Comments	Score	Comments	Score	Comments	Score
Safety	S1	Risk to Life (non operational personnel)	EHS / SC	Pass / Fail		Pass	0.00	Fail	0.00	Fail	0.00	Pass	0.00
	S2		EHS / SC	Pass / Fail			0.00		0.0		0.0		0.0
	S3	Event of Catastrophy at Plant (BakerRisk Report)	EHS / SC	Pass / Fail		Pass	0.00	Fail	0.0	Fail	0.0	Pass	0.0
	S4		EHS / SC	Pass / Fail			0.00		0.0		0.0		0.0
	S5	Egress for Emergency Response Personnel	EHS / SC	Pass / Fail		Pass	0.00	Pass	0.0	Pass	0.0	Pass	0.0
Subtotal						0.00		0.00		0.00		0.00	
Operations	O1	Operational Redundancy	SC	1 to 5	9%		5 0.5		0.0		0.0	will still require a redundant site elsewhere	3 0.3
	O2	Future Growth (underground plant)	SC	1 to 5	7%		4 0.3		0.0		0.0		3 0.2
	O3	Future Growth (office space)	SC	1 to 5	5%		4 0.2		0.0		0.0		3 0.2
	O4	Benefit of Operational Adjacencies	SC	1 to 5	10%		3 0.3		0.0		0.0		4 0.4
	O5	Planned Pipeline Construction Timeline	SC	1 to 5	3%		3 0.1		0.0		0.0		3 0.1
	O6	Employee Impact of proximity of buildings	SC	1 to 5	6%		3 0.2		0.0		0.0		4 0.2
	O7	Daily Operational Security	SC	1 to 5	10%		4 0.4		0.0		0.0		3 0.3
56%	O8	Employee Productivity	SC	1 to 5	6%		2 0.1		0.0		0.0		4 0.2
Subtotal						40.40		0.00		0.00		38.00	
People	P1	EmployeeTravel Time Impact (to/from work)	SC	1 to 5	2%		3 0.1		0.0		0.0		3 0.1
	P2	Employee Engagement / Satisfaction / Impact	SC	1 to 5	8%		2 0.2		0.0		0.0		4 0.3
	P3	Social / Team dynamics	SC	1 to 5	8%		3 0.2		0.0		0.0		4 0.3
	P5	Single Enbridge Presence (One Company One Vision)	SC	1 to 5	3%		3 0.1		0.0		0.0		2 0.1
29%	P6	Employee Disruption During Construction	SC	1 to 5	8%		4 0.3		0.0		0.0		3 0.2
Subtotal						17.40		0.00		0.00		20.00	
Construction / Other Considerations	M1	Environmental Reviews	EHS	1 to 5	3%	to be validated based on findings	3 0.1		0.0		0.0	to be validated based on findings	3 0.1
	M2	Estimated Project Cost	SC	1 to 5	3%	to be validated based on findings	3 0.1		0.0		0.0	to be validated based on findings	4 0.1
	M3	Property Naturalization	PT	1 to 5	3%		3 0.1		0.0		0.0		3 0.1
	M4	Zoning Implications	Facilities	1 to 5	3%	to be validated based on findings	3 0.1		0.0		0.0	to be validated based on findings	3 0.1
15%	M5	Project Completion Timeline	PT	1 to 5	3%	to be validated based on findings	3 0.1		0.0		0.0	to be validated based on findings	3 0.1
Subtotal						9.00		0.00		0.00		9.60	
		TOTALS (out of 5)			100%	3.34		0.00		0.00		3.38	
		TOTALS (Overall %)			100%	66.80		0.00		0.00		67.60	

Witnesses: D. Dalpe
B. Pilon

CORUNNA COMPRESSOR PLANT

MINISTRY OF ENVIRONMENT- ENVIRONMENTAL COMPLIANCE APPROVAL

PROJECT SUMMARY

This project is required so that Enbridge's Corunna Compressor Plant will comply with the terms of its Environmental Compliance Approval ("ECA") as issued by the Ministry of Environment ("MOE"). This project, which began in 2010, is near completion; however, there is an estimated $3 million of remaining work included in the budgeted capital costs for 2014. An ECA is issued by the MOE for industrial sites and sets out, among other things, the acceptable levels of noise and equipment exhaust emissions that are permitted from that site.

This remaining cost will cover the installation of a new gas after-cooler on one of the compressor units (K704), the construction of spill containment for the engine jacket-water coolers and associated piping within the 'sound wall' and compressor building area, and the construction of stairs and walkways around the turbochargers.

DESCRIPTION OF WORK

The work that began in 2010 has been the last element of a long term program at the Corunna Compressor Station to reduce the levels of engine exhaust and noise emissions from it. It has involved changes to compressor engine exhaust systems, turbochargers, gas and engine coolers and the attenuation of general plant noise sources.

Because the Corunna Compressor Plant was initially constructed in 1964, the plant design, layout and equipment, have reflected the state of compressor station technology and design of that time, and the environmental standards that were then in place. Other projects have also been completed over the years to bring the Corunna Station into compliance with the site's Certificate of Approval (C of A), as it was then known, granted to Enbridge by the MOE.

Much of this emission improvement work has been done over an extended period, dating back to the mid-1990s, with a program to conduct engine exhaust emission upgrades to ten compressor units. These were done one-at-a-time over that period, partly because of the need to have sufficient units available for storage operations, and partly because, in some cases, the technology first had to be developed to effect the improvements. The last of those compressor upgrades will be completed in 2013.

Most of these earlier projects had been intended to reduce engine exhaust, or combustion, emissions whereas much of this last project is intended to reduce the noise emission levels from the Station.

This last project installment, like much of the earlier work, has been a large undertaking for Enbridge, first in identifying, and then choosing from, the various technical solutions available, and then conducting the actual project work. This final element has been underway since 2010, with completion expected towards the end of 2013 and early 2014.

The full scope of this final project has included :

- making modifications to all of the compressor unit exhaust stacks at the Corunna Station so that the site meets the MOE's exhaust emissions standards.
- making upgrades to compressor engine exhaust silencers,
- installation of noise attenuation for all compressor turbochargers,

- modification of all of the fan assemblies on the gas after-coolers,
- the modification of the fan assemblies on seven of the compressor engine (jacket water) coolers, and
- attenuation of noise from station yard piping.

The photos below will provide an understanding of the changes that are being made to the exhaust stacks and silencers at the Corunna Compressor Station. Please

Figure 1

Before

Figure 2

After

notice the relative height of the new stacks in Figure 2 as compared with the earlier ones shown in Figure 1. Also visible in the above photographs are the jacket- water coolers and associated piping that are shown to the left of the exhaust stacks and compressor buildings. The Figure 3 below shows a new gas after-cooler that is replacing the existing unit on compressor unit K704.

Figure 3

NEED

This project is one element of a broader program of work that Enbridge has completed to bring its Corunna Compressor Station into compliance with the terms of its Environmental Compliance Approval (ECA) as provided by the Ministry of Environment for Ontario (MOE). The ECA for this Station, formerly known and referred to as Certificate of Approval (C of A) No. 5973-759K56, was issued by the MOE on October 31, 2008 contains the environmental terms and conditions under which the station is allowed to operate.

Much of this ECA compliance work, most notably the engine emission upgrades that have been completed on ten of the compressor units, has been completed over a long period of time. This final element, however, has been underway only since 2010 with completion expected in 2014. The remaining work for 2014 is essential to the completion of the project.

COSTS

The $3 million that is included in the 2014 budget for this project is the cost of a collection of activities that are required to bring it to completion. Among the larger components of this is the installation of a new gas cooler for the K704 compressor unit at an estimated cost of $1 million. This cooler has been fabricated and delivered to the Corunna Station but will not be installed until early 2014.

There is another $1 million of cost expected for the construction of a 'floor' to be built in the area between the three compressor buildings and new acoustical walls that will be constructed to dampen noise emissions from the exhaust stacks and turbochargers. This will provide containment for the collected rain and snow in that area, as well as and any potential glycol leaks that could occur in the piping and jacket-water coolers for each of the compressors. A jacket-water cooler for a gas compressor is the equivalent of a radiator in a car.

The balance of the cost is that estimated to build the stairs and walkways around the new exhaust stack and turbocharger equipment that has been installed over the last several years, as well as other costs related to the project completion and clean-up.

WELL INTEGRITY PROGRAM

PROGRAM SUMMARY

The 2014 through 2016 Storage Operations forecast includes the costs of a number of activities that are required to ensure the continued integrity of the wells that Enbridge has in its storage system. The integrity of its wells is of the highest importance for an underground gas storage operator. The wellhead and casing is the only equipment that isolate the reservoirs, and the gas pressures they contain, from release to the atmosphere, and there are limited means by which to inspect and repair it. The failure of this equipment could result in a significant release of gas that would take weeks to get under control.

There are three well integrity activities included in this program that Enbridge will be conducting over the forecast period; a well pressure testing program, to determine if the wells have the ability to withstand the gas pressures required of them, the replacement of well casing and wellheads on those wells, where corrosion or some other mechanical problem have made it necessary, and the drilling of new wells that are required to replace the accumulated gas injection/withdrawal flow capability that has been lost to the casing re-line work and well abandonments.

Well Casing/Wellhead Replacement - As a result of regular inspection programs, wells are occasionally identified that will require the replacement or reline of the well ‘casing’. This casing is the pipe that is installed down the well bore and into the gas storage reservoir. In almost all such cases a new wellhead will also be required.

There is no real option when it comes to doing the casing replacement work; either the work is done or the well must be abandoned. Whichever action is taken, it must be done within a year of identifying the problem based to meet Ministry of Natural Resources (MNR) requirements.

The 2014 to 2016 budgets assume that two of these casing replacements will be required in each year at a cost of about $375,000 each. At this point it is expected that at least three wells will be upgraded in 2013, possibly more if the logging or pressure testing programs were to identify other candidates. Though the cost of this work is not insignificant, the alternative would be to abandon the well, and eventually, to drill a replacement well. The cost of drilling a replacement wells is significantly higher and so these casing replacements on existing wells do offer a considerable economy or productivity gain as compared with that alternative. The annual cost forecasts for this project are approximately $750,000 per year from 2014 to 2016.

Well Pressure Testing - Enbridge must to inspect and monitor all of the wells that penetrate into its storage reefs so as to remain in compliance with the CSA Z342 Hydrocarbon Storage Standard, as adopted under the Oil, Gas & Salt Resources Act (OGSRA). The OGSRA is administered and enforced by the Ministry of Natural Resources – Petroleum Resources Section.

Enbridge has conducted regular corrosion inspections on its wells through a well logging program that has been in place for years and, in 2012, it also initiated a 'pressure testing' program on all of its wells. This second program has not been a regular element of Enbridge's well integrity work, but was initiated following the results of a similar program that had recently been conducted as part of the Company's unregulated storage development effort. This program ensures compliance with Section 5.4(a) of the OGSRA, which stipulates that the Operator of a well "shall not use oil or gas wastefully or allow it to leak or escape from natural reservoirs".

As a part of this program, Enbridge is also upgrading any wellhead that does not meet the current CSA Z341 Standard. Because the pressure testing program requires that plugs be set to isolate the storage reef from the well, it provides a good opportunity to replace these wellheads. The new wellheads will provide an increased safety and reliability factor, align Enbridge with storage industry best practices and, generally, provide better protection of employees and the public as well as ensuring the best interests of EGDI's gas customer

Figure 1 below, is a 'before' picture of a typical wellhead, in this case for the Tecumseh Dow #6 well, which did not meet the Standard and needed replaced. The original wellhead had been buried underground which, in and of itself, did not comply with the Standard. In addition to this, the wellhead also had threaded connections for both the casing bowl (yellow arrow) and the tubing spool (white arrow) which did not meet the Standard and the tubing spool was designed with only one entry point into the well (green arrow), which again is not to the Standard.

Figure 1

Before

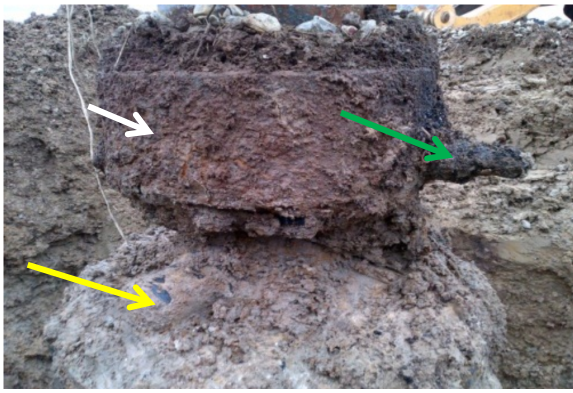


Figure 2

After

The ‘after’ picture of this wellhead is shown as Figure 2. It has all flanged connections, as opposed to threaded, and has two entry points into the tubing spool which is important for well control should the other be damaged.

The total annual cost forecast for all activities associated with the well pressure testing program is $1.78 million for 2014, $1.54 million for 2015 and $1.99 million for 2016.

Drilling Replacement Wells - The well integrity work in the 2014 through 2016 period include costs for the drilling of two injection/withdrawal (I/W) wells, one in each of 2015 and 2016. These wells will provide I/W capacity to replace that which has been lost in recent years due to a combination of well abandonments and casing re-lines.

Enbridge intends to drill these wells using horizontal well drilling technology. With the combined geophysical and geological information that the Company now has for its reservoirs, it is better able to identify the best locations to drill these wells so as to optimize their individual gas flow capabilities as well as that of the reservoir. In the longer term, as other horizontal replacement wells are drilled, this strategy will eventually result in the elimination of most, if not all, of the vertical I/W wells in Enbridge's storage pools. And that will mean that there will be a significant reduction in the total number of wells within EGD's storage system. This strategy will also provide reductions in the associated well operating and maintenance costs, and a lower operating risk as there will be fewer wells that have the potential for integrity problems.

The drilling of these wells is expected to cost $2.5 million each and the 2016 cost includes an additional amount to install the additional gathering pipelines needed to 'tie' these wells into the existing gathering pipeline infrastructure. The annual cost forecast for the replacement well drilling program is $2.5M in 2015 and $3M in 2016.

The following will provide a more detailed discussion of each of these well integrity activities.

A. WELLHEAD/WELL CASING REPLACEMENT

DESCRIPTION OF WORK

This program has become a normal part of the ongoing, maintenance capital that is required in Enbridge's Gas Storage Operations. The need for this type of work is normally identified through well integrity inspection programs that the Company conducts for all of its wells on a regular cycle. This inspection program is required to ensure compliance with the CSA Z341 Storage Standard, as adopted by the Ministry of Natural Resources under the Ontario Oil, Gas & Salt Resources Act. The inspections identify any wells that require work to bring their casing into compliance with that Standard.

A casing replacement job first requires that the wellbore is isolated from the storage reservoir. To do this a wireline service company is engaged to set 2 plugs in the well. Once this has been done, and the well has been isolated from the reservoir, a service rig is brought onto location. The rig and crew are required to remove the old wellhead and to install a new one. This is specialized work as, at this point, there is nothing other than the plugs to isolate the reservoir from the atmosphere.

Following this, a smaller diameter casing is then run into the well and cemented in place. With that complete, the service rig is released and a cable tool rig is brought on site to drill out the plugs and to clean out the well to the original total depth. The cable tool rig is then released and a new flow loop (well head piping) is fabricated and installed on the new wellhead. It is only then that the well can be put back into service.

The photographs shown below as Figure 3 and Figure 4 will provide a visual of what can be seen as the work is done and what the finished wellhead and flow loop will look like.

Witnesses: D. Dalpe
B. Pilon

Figure 3

Service Rig Over a Well

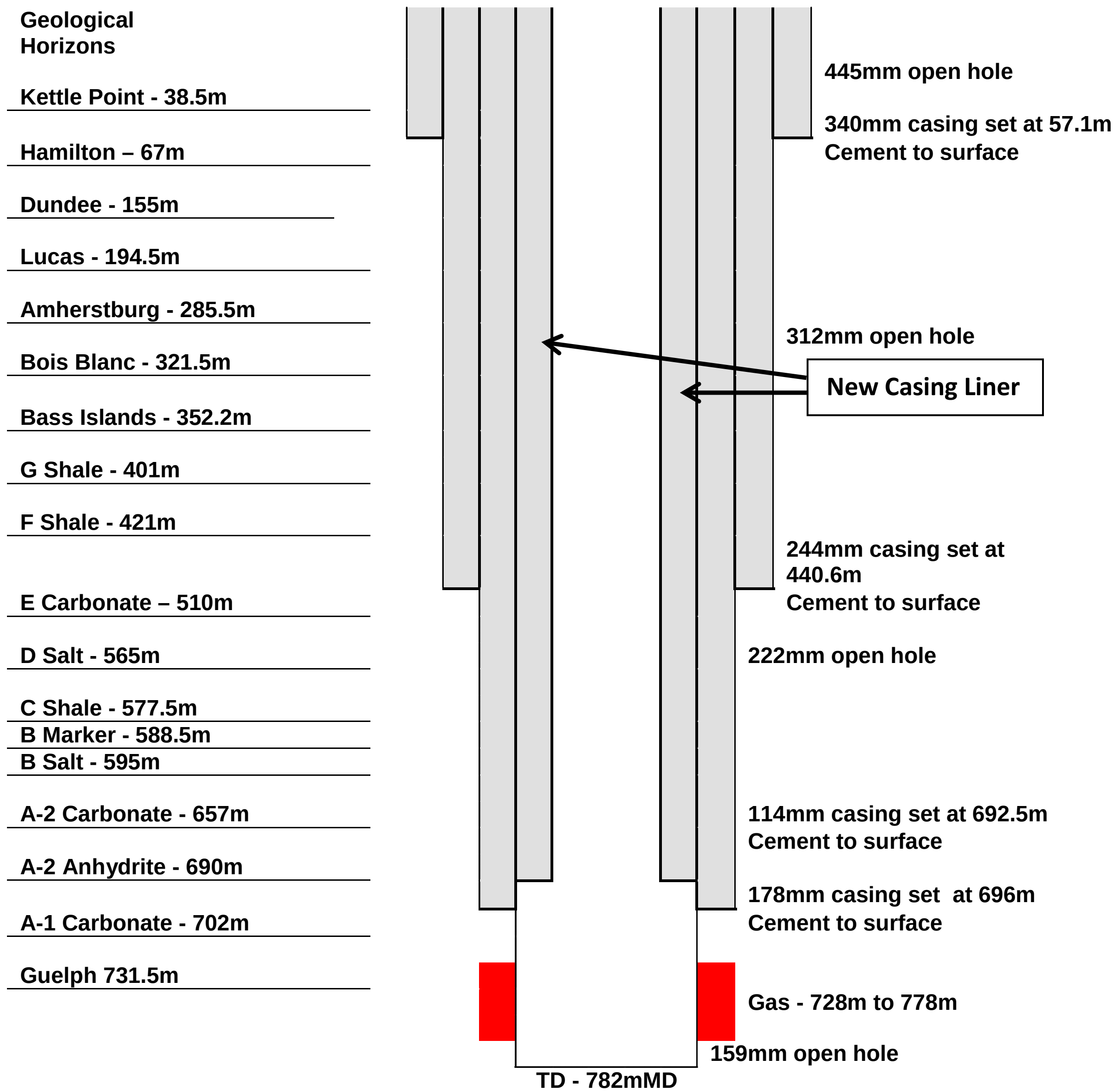
Figure 4

Completed Wellhead with
Flow Loop and Pipeline Valve

As for what changes are made to the well 'downhole', Figure 5 on the following page is a schematic of a typical re-lined well. The new 'string' of casing is the innermost shown on the schematic. Because it must be of a smaller diameter than the original string, it does cause some restriction in the injection/withdrawal flow rate of the well.

Figure 5

SCHEMATIC OF A RE-LINED WELL BORE CASING



Witnesses: D. Dalpe
B. Pilon

NEED – WELLHEAD/CASING REPLACEMENT

The drilling, operation and maintenance of gas storage wells is regulated by the Ministry of Natural Resources under the Ontario Oil, Gas & Salt Resources Act (OGSRA) and all associated Regulations and Operating Standards, including the CSA Z341 Hydrocarbon Storage Standard.

These Acts and Standards dictate that, if a well has high corrosion that exceeds certain tolerances, then it must be repaired, isolated from the reef or abandoned. The well may be isolated from the reef, or suspended, for 12 months or less. By the end of that time the well must either be abandoned or repaired, so ultimately the decision is whether to repair or abandon the well.

Wells with high corrosion provide a potential pathway for leakage from the reservoir which would compromise not only the integrity of the well, but also the reef. If the integrity of the reef were lost, it could no longer be used for storage until the integrity issue was repaired. The implication of such a well failure would be the loss of a significant gas commodity and the loss of that particular storage reservoir and its storage service for the Company and its customers.

The photograph shown below as Figure 6 illustrates the corrosion that can occur to well casing. The corrosion can be seen as pitting on the outside of the pipe. Some level of corrosion is not unusual but calculations set out in the CSA Z341 Standard will determine if the depth of penetration or rate of growth of that corrosion, as seen in the casing corrosion logs, will necessitate this remedial work.

Figure 6

Examples of Well Casing Corrosion

ALTERNATIVES CONSIDERED

As has been mentioned, the choices available to Enbridge are to either repair or abandon a well that has integrity problems. The cost of these casing replacements are normally about $370,000 each, whereas the cost of abandoning the wells, and subsequently drilling a replacement well, would be in the order of $1.5 million, for a vertical well, and closer to $2.8 million for a horizontal well. These well repairs will prolong the useful life of a well for many years with the obvious benefits for gas storage customers in deferring that replacement cost.

COSTS

The annual cost forecasts for this project are approximately $750,000 per year from 2014 to 2016.

The cost of this replacement work will vary from well to well, but generally has come in at a cost of somewhere between $310,000 and $390,000 per well in recent years. The number of wells requiring this work in any one year will also vary; in recent years it has ranged from zero to as many as four. The 2014 through 2016 budgets assume that two of these will be done in each year at an average cost of $375,000 each (plus inflation). Where wellheads are replaced there is also the need for piping changes to be made to tie the new wellhead into the gathering pipeline.

B. WELL INTEGRITY – PRESSURE TEST AND WELLHEAD UPGRADE

DESCRIPTION OF WORK

The well pressure test program is done on a pool by pool basis and, for this reason, must be done over a number of years. It would not be operationally possible for Enbridge to conduct this work on all of its wells in only one or two years. To conduct these tests, the reservoir pressure must be sufficiently low so as to facilitate the work and reduce the risk of a well control problem. To achieve this, Enbridge must schedule the use of its storage pools in the preceding gas withdrawal season to allow the targeted pool to be brought to the pre-determined work-over pressure.

Prior to commencement of the work on each well, it is determined if the well will require the replacement of its wellhead equipment. Although all of Enbridge's Gas Storage wells are in compliance with the MNR Regulations, many do not meet current Standards. They are in compliance because of grandfathering that was adopted as the

Standard has changed; however, some wells have not met the accepted Standard for over 20 years.

There are a number of characteristics of some of Enbridge's wellheads that do not meet the current Standard and the Company has determined that it will replace those wellheads as an element of the pressure test program. For example, some wellheads use threaded rather than flanged fittings, some don't provide redundant access to the wellbore and others do not meet the Standard simply because they are installed below grade and buried in soil. All of these were acceptable at one point but no longer comply with the current Standard. Other wellheads are simply of a design and pressure rating that is too close to the maximum working pressure of the pool and offer little or no margin of comfort.

Although the pressure test does not require these wellhead replacements, the nature of the pressure test work, provided Enbridge with an ideal opportunity to change out some of this equipment. By doing so it could eliminate the high consequence risk associated with that equipment and avoid the significant costs associated with lowering pool pressure, mobilizing equipment and setting downhole plugs to do so at some other time.

Pressure testing of the wells is achieved by mechanically isolating the wellbore from the reef, removing and gas and filling the wellbore with water and then applying a surface pressure equivalent to 1.1 times the maximum operating pressure (MOP) of the reef. If a wellhead is required, the old wellhead assembly is removed and the new wellhead assembly is installed prior to the pressure test.

If the pressure test is deemed a success, the mechanical separation is removed and communication with the reef is re-established. If a new wellhead was required then a new flow loop will also be installed and the well would be put back into service. If the well failed the pressure test then, by Regulation, it would either be repaired or abandoned. The repair of a well reduces the injection/withdrawal (I/W) flow capability of the well as the repair reduces the diameter of the casing. If the well is abandoned then the total flow requirements from the pool must be recalculated to determine if a new well will be required to replace the abandoned well.

NEED – PRESSURE TEST AND UPGRADE

Enbridge determined that there was a need for this program as a result of the findings of an earlier well pressure test program that was conducted by the unregulated storage business as part of its storage development work. That program, conducted on Enbridge's four oldest storage reservoirs, had tested 74 wells, or half of all of the wells in the gas storage system. Of those wells, a significant number had near surface corrosion issues and, as a result, approximately 1 in 7 of the wells tested had to be abandoned.

Even though the wells in these four pools had all had casing corrosion logs run on them on a regular basis, they alone were not able to identify some of the problems that were found through the pressure testing and wellhead upgrade work. It was because these integrity issues were discovered, that it was determined that the balance of the wells would also be pressure tested and upgraded to meet current Standards.

To this point, 21 of the remaining 74 wells have been tested, 6 wells remain to be tested in 2013 and the remaining 47 will be tested over the 2014 through 2016 period. There is a high probability that there will be a number of additional wells that will require repair or abandonment as a result of that program.

ALTERNATIVES TO PRESSURE TEST CONSIDERED

Because of the physical characteristics of a well, there are few means by which to inspect it once it is in operation. Regular well logging is an effective tool to inspect well casing for the effects of corrosion, and importantly, to monitor and determine the rate of change in any corrosion seen. However, corrosion logging is not able to see wellhead or near wellhead casing corrosion or problems that may not be related to corrosion.

This is why Enbridge believes that the pressure testing program is important, especially at this point in the life of the wells in its storage system. For many wells, such a test has not been completed over the life of the well. And a well integrity problem, unlike an integrity problem on a pipeline, cannot simply be uncovered and cut out as part of a follow up inspection. If a well were to fail it would likely be at a time when reservoir pressures were high, and result in a significant gas release. It could not easily be controlled and would take weeks, if not months, to play itself out and be corrected; not minutes as would be the case for a pipeline failure.

COSTS

The total annual cost forecast for all activities associated with the well pressure testing program is $1.78 million for 2014, $1.54 million for 2015 and $1.99 million for 2016.

Much of the pressure test program cost, in each year of the forecast, is dependent upon the number of wells that will be tested. As the program is being conducted on a pool by pool basis, and the sizes of the pools and the number of wells in each pool vary, there are year over year cost differences for this program.

The cost of each pressure test is about $35,000 but this increases to about $75,000 if the wellhead is changed out. In addition to these costs this program also includes the costs for a number of related activities. Because most of the wells tested will be fitted with new wellheads, the program includes the cost of replacing the wellhead piping, or ‘flow loops’, required to connect these new wellheads into the gathering pipelines. Similarly, many of these wells will also require the replacement of the pipeline valves that isolate the gathering pipelines from the wells; the cost of these valves is about $30,000 each. And in virtually all cases, the Company is replacing the pipe barriers that currently surround the wells, with security fences.

The estimated $1.78 million cost for 2014 is based on testing 12 wells in the Wilkesport Pool. Of these, it is estimated that 10 wellheads will require replacement. The cost of the pressure testing of 12 wells, including 10 wellhead replacements is forecast at $820,000. The 2014 program includes the associated cost of some $550,000 for flow loop changes and $200,000 for pipeline valve replacements. The Wilkesport well testing will also include the cost of lowering the wellheads and replacing the protective pipe barriers, forecast at $200,000.

The $1.54 million cost estimated for 2015 is based upon testing 9 wells in three different pools; Ladysmith, Chatham D and Black Creek. Of these, it is expected that 7 wellheads will require replacement. The cost of the pressure testing of 9 wells, including 7 wellhead replacements is forecast at $750,000 (additional cost because of having to work at three different pools). The 2015 program includes the associated costs of approximately $400,000 for required flow loop changes and $150,000 for pipeline valve replacements. In addition to this there will be cost for both fencing and the addition of laneways necessary to access these wells, forecast at $200,000.

The $1.99 million cost estimated for 2016 is based on 26 wells being tested in the Crowland pool; with all of them requiring wellhead replacements. These testing and equipment costs will be lower as these wells are shallower, they operate at a lower pressure, and have smaller casing and wellhead equipment than do wells in Lambton county. Enbridge estimates that the cost for each well test and wellhead replacement at Crowland is approximately $50,000. The 2016 program includes associated costs of approximately $690,000 to replace the wellhead flow loops.

C. REPLACEMENT INJECTION/WITHDRAWAL WELL DRILLING PROGRAM

DESCRIPTION OF WORK

Prior to drilling these wells, Enbridge will identify the storage reservoirs where gas injection/withdrawal ("I/W") capacity has declined to the point where it is felt that a replacement well is required. Using the available seismic information and the results of the reservoir modeling work, a target location for the pool will be determined and a drilling program created. This information will be filed with the OEB as part of a 'Request for Leave to Drill' Application. Assuming that the request is approved, the required drilling contractors will then be engaged.

It is Enbridge's intention, whenever possible, to drill replacement wells using the horizontal well drilling technology that is available today. Normally the drilling will begin with a cable tool rig to set the conductor and surface casing. When that is complete the cable tool rig is moved out and a rotary rig is moved in.

The rotary rig drills an 'intermediate' hole and then sets casing. This casing is required by Regulations to provide well control capability. At this point a directional drilling crew and their equipment is brought in. They begin to drill directionally, building the hole angle to 50^0 from vertical and then set production casing into the top of the reef. From that point, they continue to drill and build angle from 50^0 to 90^0 within the reef and then continue drilling horizontally to total depth ("TD") in the target zone of the reef. At this point the well drilling is complete, the rig is released, the gathering line and flow loop are installed and the well is put into service.

The major differences between drilling a vertical well and drilling a horizontal well are that the horizontal well requires a larger rotary rig, a longer period of time to drill the well and additional contractors and equipment to drill the horizontal section of the well.

NEED – REPLACEMENT WELLS

For many years Enbridge has conducted a well logging program by which, on a regular cycle, it inspects each well for corrosion. In addition to this program, the Company is currently conducting a pressure test all of the wells in its storage pools to identify any well casing leaks. These inspections are conducted by Enbridge in order to comply with Regulations of the Ministry of Natural Resources (MNR). This is set out under the CSA Z341 Storage Standard which has been adopted by the MNR under the Ontario Oil, Gas & Salt Resources Act.

When a potential well problem is found through the well integrity inspections, these same Standards require that Enbridge do further work to mitigate the risk of a well failure. It must either replace the top one or two lengths of a well's casing, 're-line' the entire well casing with a new, smaller diameter casing string, or simply abandon the well altogether. Of these three possible outcomes, the last two will result in reductions to the gas injection and IW capacity of the well and, ultimately, of the reservoir into which it is drilled. As a result, the drilling of a replacement well or wells will eventually be required to replace the I/W capacity that has been lost.

Both of these inspection programs, the well logging and pressure testing, have led to a number of well abandonments and re-lines in recent years with a resulting loss of capacity to inject and withdraw gas. Table 1 below lists the wells that Enbridge has either re-lined or abandoned since 1990 as well as the estimated loss of Absolute Open Flow (AOF) capacity that results. AOF is a measure of the rate at which the well can deliver gas at the wellhead, at atmospheric pressures.

Table 1

Estimate of AOF Reductions since 1990

Year	AOF Reductions*					Yearly AOF Reduction mmcf/d
	Wells Relined	Reline AOF Reduction mmcf/d	Wells Abandoned	Abandoned Well Type	Abandonment AOF Reduction mmcf/d	
1990	TKC#19		None			
1990	TKC#25		None			
1996	TKC#4	17.7	None	n/a	0.0	17.7
1996	TKC#16	2.4	None	n/a	0.0	2.4
1996	TS#8	10.5	None	n/a	0.0	10.5
1998	None	0.0	TD#5A	Obs.	171.8	171.8
2000	TKC#26	24.7	TD#4	A-1 Obs.	0.0	24.7
2000	None	0.0	TKC#32	Obs.	125.7	125.7
2001	TS#11	23.7	None	n/a	0.0	23.7
2002	TKC#8	7.5	TS#5	Inj/Withd.	115.0	122.5
2002	TD#21	24.1	None	n/a	0.0	24.1
2003	TC#4	10.2	TKC#12	Inj/Withd.	63.0	73.2
2003	TS#12	20.9	DM#3-21	Inj/Withd.	76.0	96.9
2003	None	0.0	DM#2-20	Inj/Withd.	7.0	7.0
2004	None	0.0	TKC#11	Obs.	0.0	0.0
2005	TKC#51	41.0	None	n/a	0.0	41.0
2005	TS#10	0.0	None	re-injection	0.0	0.0
2006	TC#1	27.5	None	n/a	0.0	27.5
2007	TD#9	0.0	None	n/a	0.0	0.0
2007	TD#10	0.0	None	n/a	0.0	0.0
2008	TD#12	0.0	None	n/a	68.9	68.9
2009	None	0.0	TKC#33	Inj/Withd.	43.0	43.0
2010	None	0.0	TKC#15	Inj/Withd.	40.0	40.0
2010	None	0.0	TKC#41	Inj/Withd.	57.0	57.0
2010	None	0.0	TKC#50	Inj/Withd.	0.0	0.0
2011	TKC#43	8.0	None	n/a	0.0	8.0
2011	TKC#44	20.0	None	n/a	0.0	20.0
2012	None	0.0	TKC#1	Inj/Withd.	100.2	100.2
2012	None	0.0	TKC#25	Inj/Withd.	143.6	143.6
2012	None	0.0	TKC#26	Inj/Withd.	116.0	116.0
TOTALS		**238.4**			**1127.2**	**1365.6**

The total AOF reduction of 1366 mmcf/d is equivalent to losing 11 vertical wells

* AOF's are calculated at 1100 psig at surface.

** Where deliverability is unknown field averages are used to estimate the AOF
AOF reduction = 15% for 5 1/2' reline and 30% for 4 1/2" casing reline

Witnesses: D. Dalpe
B. Pilon

As can be seen in the ‘TOTALS’ line near the bottom of the table, this work has resulted in the loss of some 1.4 million cubic feet of Absolute Open Flow (“AOF”) capability per day, which is roughly the equivalent of losing 11 of Enbridge’s average vertical wells. With the continuation of the well pressure test program over the next 4 years, it is expected that there will be more abandonments, further aggravating this reduction in capacity. The early results of the pressure testing that has been done has seen roughly 1 in 7 wells abandoned, with an associated loss in I/W flow capacity.

In the last 10 years only one well, the Wilkesport #14H well, has been drilled to replace some of this lost utility capacity. This well was drilled shortly after the drilling of 3 unregulated storage wells in 2008. And, in view of the advanced age of many of Enbridge’s I/W wells, and the outcomes of the well pressure testing program, it is expected that further abandonments and re-lines are likely to occur and that more capacity will be lost over the next few years. To replace this lost capacity, Enbridge expects to be drilling a number of replacement wells in the future; the two wells planned for 2015 and 2016 are the beginning of that work.

There are some 110 I/W wells in all of Enbridge’s storage pools. The majority of these wells are over 30 years old and more than 40 of them, or about a third, are in excess of 45 years old. The list below summarizes the ‘demographic’ profile of all of the wells within Enbridge’s gas storage pools.

- 13 wells were drilled prior to 1960 (53+ years old)
- 30 wells were drilled from 1960 to 1969 (43 to 52 years old)
- 48 wells were drilled from 1970 to 1979 (33 to 42 years old)
- 24 wells were drilled from 1980 to 1989 (23 to 32 years old)
- 23 wells were drilled from 1990 to 1999 (13 to 22 years old)
- 9 wells were drilled after 2000 (0 to 12 years old)

Given the age of these wells, Enbridge will have to plan for the abandonment or repair of many of them in coming years and should also formulate a well replacement strategy.

ALTERNATIVES TO DRILLING REPLACEMENT WELLS

There is no real alternative available to the Company other than to choose whether it will drill vertical replacement wells or horizontal wells. Horizontal wells have advantages over vertical wells in that they provide a much greater effective well bore contact with the storage reservoir. A vertical well may only access from 10 to 200 feet of reservoir in a typical reef, depending on the nature of the storage pool, while a horizontal well can access greater reservoir sections of up to 2000 feet.

Figure 7 depicts the comparative reservoir contact that these two types of wells can have. It should be noted that this is meant for illustration and that the vertical scale is altered. The horizontal wells that have been drilled by Enbridge to date are, on average, about 3.4 times more productive than its vertical wells yet cost less than twice the cost of them to drill.

Figure 7

At this point, only one of Enbridge's storage pools, the Ladysmith Pool, has been developed solely with horizontal I/W wells. The two horizontal wells into this pool, more than meet any deliverability needs that are required of it. Conversely, the Black Creek Pool has been developed with one vertical and one horizontal injection well. The open flow of the Black Creek horizontal well, at 230 million cubic feet per day, is approximately 4.6 times the 50 million cubic feet per day open flow of the vertical well in the same pool. Of Enbridge's storage reservoirs, these were developed most recently, at a time when the horizontal drilling technology has been available.

COSTS

The annual cost forecast for the replacement well drilling program is $2.5 million in 2015 and $3 million in 2016. This assumes adding one replacement well in each of those years.

These replacement wells are expected to cost $2.5 million each to drill and complete.

There are many elements to drilling a horizontal well, including:

(i) the cost of acquiring drilling permits and related geological and regulatory costs, totaling about $100,000

(ii) installing and removing a drill 'pad', plus related clean up and land damage settlement, totaling about $450,000

(iii) the cost to drill ($1,300,000), case ($250,000), cement ($150,000), log ($200,000) and equip ($50,000) the well.

The wells will also require some pipeline additions to tie them into the gathering system and there is an additional $0.5 million included in 2016 for this work.

In time a horizontal well replacement program will ultimately lead to a reduction in the total number of wells within Enbridge's storage system. Apart from the cost savings that are available to the Company through these comparative performance advantages, there are also economies to be enjoyed in terms of lower surface rentals paid and in ongoing well and well site maintenance costs. And with a reduced number of wells to log there will also be a reduced risk associated with such activity.

STORAGE POOLS INTEGRITY

OBSERVATION WELL DRILLING

PROJECT SUMMARY

Enbridge is currently engaged in a program to drill observations wells in a number of locations near its storage reservoirs. Six such wells will have been drilled by the end of 2013 and it is expected that as many as eight more will be required. Two are planned for each year from 2014 through 2016. These wells are intended only to provide information to the Company regarding the presence, extent and qualities of gas bearing rock near its storage pools; they are not suitable for, and will not be used for, gas injection or withdrawals.

The locations of these wells have been chosen based largely upon information gathered through a recent seismic program conducted over the pools. That information has been combined with the Company's previous understanding of the pools as provided from other wells that have been drilled into, or near, the pools over the years.

The additional information gained from these observation wells, when used in conjunction with this previously held information, will provide Enbridge with a much better understanding of its storage reservoirs and, thereby, of its stored gas inventories. Additionally, it will also provide Enbridge with a better understanding of whether the present Designated Storage Area (DSA) boundaries adequately protect the gas bearing zones of each pool.

The forecast cost of the observation well drilling program is $1.85 million in 2014, $2.45 million in 2015 and $1.6 million in 2016.

DESCRIPTION OF WORK

This project will see the drilling of a number of relatively low cost observation wells in strategically chosen locations near Enbridge's storage pools. These wells are lower in cost than injection/withdrawal wells because of the smaller diameter casing that is required for them.

The well locations chosen will allow the Company to confirm or enhance its preliminary understanding of the geology of Enbridge's storage pools and of the structures adjacent to them as has been suggested by recently acquired seismic data. The combination of the well and 3D seismic data will help to confirm the extent of the reef and other gas bearing zones of each of the storage pools. Enbridge is required to get a permit to drill these wells and discusses the well locations with the Ministry of Natural Resources in the course of acquiring the permit.

To date, five of these wells have been drilled and another is planned for 2013. The 2014 through 2016 budgets include the costs to drill two additional wells in each year. Before it is completed, the entire program may see as many as 14 observation wells drilled throughout Enbridge's gas storage reservoirs. These wells will be completed and equipped to monitor and communicate gas pressures back to the Control Room.

Although not a cost related to the drilling of observation wells, there are two additional activities associated with improving the integrity of the Enbridge storage reservoirs. The first is two ensure that a number of wells that had been drilled and abandoned during the production period of the pool's life, are abandoned to a standard that does not compromise the storage reservoir. This requires that the former well be located and then 're-entered' and abandoned to meet this standard.

The other activity included in this program is the acquisition of additional storage rights so that the DSA boundary on a pool or pools may be moved to better protect them. The drilling of observation wells will determine the extent to which any DSA boundary needs to be expanded.

NEED

The primary driver behind the timing of this drilling program, as well as that of several other projects, has been Enbridge's decision to improve its gas storage inventory management capabilities. Enbridge had consulted externally on current industry practices regarding inventory management (GLJ Ltd. report "Inventory Discrepancy Analysis – Gas Storage Pools" (Dec. 2007), the Dowdle & Assoc. report "Third Party Review Practices and Procedures Gas Storage Inventory Verification" (Apr. 2009)), and it was determined that a number of projects should be completed to bring Enbridge in line with these practices.

In particular, it is standard industry practice that Storage Operators will have observation wells into zones adjacent to their storage pools to monitor any pressure changes in those zones. Over its history, Enbridge has maintained a number of observation wells but many of these were originally drilled as production or injection/withdrawal wells within the storage reef boundary and useful only for monitoring reservoir pressures. It has not had many observation wells into low-permeability, low porosity zones outside of, but adjacent to, the storage reservoirs. A recent seismic program completed on the pools has identified a number of these potential low porosity zones and the observation wells are the only means by which to confirm their presence and the characteristics of them. The need for such observation wells is recognized in the CSA Z341 Storage Standard.

In view of ongoing concerns with apparent discrepancies in its gas inventories, and the awareness of the available technologies that could help it to understand and explain them, the Company determined that it would undertake a number of projects. From 2008 through 2011 Enbridge had conducted a 3D seismic study of all of its storage reservoirs. This is a newer generation of seismic data collection and is widely used by underground gas storage operators. The information acquired through the 3D seismic programs has provided Enbridge with much better data with which to understand its storage pools structures, to more accurately identify any potential gas migration paths from the reservoirs and, ultimately, to confirm the pool boundaries.

However, to get the best value from this data, it is necessary to combine it with the information gained from well drilling. Much information is available from existing wells but there are areas of the pools, especially outside of and adjacent to the reef, in which there was not sufficient well data to provide a more complete geological and geophysical understanding of the pools. As a result, these additional observation wells locations were chosen. As it becomes available, this additional well data will complement and inform Enbridge's interpretation of the 3D seismic data and, ultimately, its ability to model and understand the storage reservoirs and to better manage its gas inventories.

In addition to Enbridge's responsibility to understand its storage reservoirs, it also has a responsibility, as a storage operator, to ensure that its storage pools are adequately protected by an appropriate DSA boundary. The DSA boundary ensures that no third party can be granted a permit for the purpose of drilling a well into, or in close proximity to the storage pool, or of fracing a well within a mile of it. Similarly, by including the land within the DSA boundary, there is assurance that the landowner, or storage rights owner, will be recognized and given fair compensation for having their sub-surface rights designated as a storage area.

Figure 1

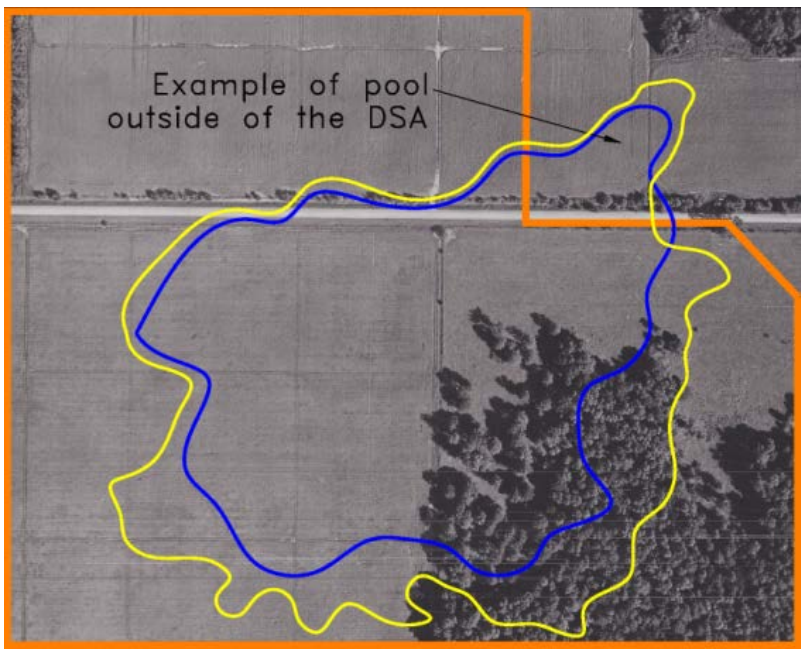
As an example, the pool map shown as Figure 1, to the right, provides a depiction of the size and position of Enbridge's Coveny storage DSA (in amber). The dark blue contour line denotes the extent of the storage reef and the yellow contour shows the A1 Carbonate rock near to it, as confirmed by seismic and drilling information. This well information will help Enbridge to ensure that these features are all within, and protected by, the Designated Storage Area (DSA) boundary.

Many of Enbridge's DSA boundaries were determined up to a half a century ago, based upon information that was derived from the wells that had been drilled during the production life of the storage reservoirs. As this new sub-surface information has become available, Enbridge also has an obligation to ensure that the DSA boundary is still seen as adequate to protect the pool.

For Enbridge Gas Storage, the recently conducted seismic program has provided such new information. And for one or more pools, that seismic data has suggested that some of these storage pools, and associated zones of low-permeability and porosity, may be closer to the DSA boundary than Enbridge had previously thought.

Figure 2, below, is a schematic diagram that depicts such a problem. The orange outline delineates the DSA boundary and, the blue and yellow contours depict the storage reef, and an associated A1 Carbonate zone, that both extending beyond it. It would be in such a situation that an observation well would not only help Enbridge to understand the storage reservoir and its gas inventories, but also confirm if there was a need to revise the DSA boundary.

Figure 2



The observation wells will confirm the presence of areas of porous, low-permeability rock in close proximity to the reservoirs and will make it possible to determine if these are in communication with the storage pools. The study of drill 'cuttings' and geophysical logs will also provide geological engineers with the information that they require to determine the porosity of the formations and, thereby, their capacity to hold gas. The wells will provide immediate information about the nature of these structures and observation of the longer term well pressure behaviours of them will help to determine if they are in communication with the storage reservoirs.

Witnesses: D. Dalpe
B. Pilon

ALTERNATIVES CONSIDERED

The drilling of wells is the only means by which to confirm the interpretation of geological and geophysical information that has been suggested by other sources. In its effort to better understand its storage reservoirs, and to improve its gas inventory management, Enbridge has actively acquired this information recognizing that it additional well information would be required to complement it.

For Enbridge, it has conducted a comprehensive seismic program using state of the art '3D' seismic technology. It did so to get the best information possible, and to assemble the best understanding that it could of its storage pools, of the adjacent rock zones and, ultimately, of its gas inventories. And so the drilling of observations wells, although not a necessity, is the only means by which to leverage the seismic data, and to provide geologists and geophysicists with the information and the certainty that they require to provide Enbridge with that understanding of its storage pools.

The information gained from them is essential to the use and refinement of the seismic information and, ultimately, to the Company's understanding of, and ability to protect, the storage pool. Even though the 3D seismic data is of high quality, it is only inferential and must be confirmed and correlated with the information acquired from drilling.

COSTS

The forecast cost of the observation well drilling program is $1.85 million in 2014, $2.45 million in 2015 and $1.6 million in 2016.

The costs for most of the observation wells drilled to this point are between $790,000 and $850,000 each. These wells are lower in cost than a typical injection/withdrawal well as the casing sizes are much smaller for an observation well. The cost of each of the two wells to be drilled each year between 2014 and 2016 is estimated at $800,000, including the costs for the pressure monitoring equipment. The costs for each of these wells will include the cost of the permitting, drilling, casing and wellhead equipment, and will also include the cost of an OEB Technical Review of the wells prior to granting drilling permits.

In addition to these costs, the program forecast also includes an amount in each of 2014 and 2015 to acquire additional storage leases, should it be determined that the Designated Storage Area boundaries will require adjustment to adequately protect the storage pool. The annual cost for the acquisition of additional storage leases in 2014 and 2015 is estimated at $250,000.

Lastly, the forecast includes an amount of $600,000 in 2015 intended to allow for the location and re-abandoning of several wells that had been abandoned prior to designation of the pool as a storage pool Those original abandonments would not have been completed to a gas storage standard and so Enbridge intends to ensure that they meet that standard and that the pool integrity is not in question as a result of that uncertainty.

CAPITAL BUSINESS AREA: BUSINESS DEVELOPMENT & CUSTOMER STRATEGY

Summary

1. The purpose of this evidence is to present the Ontario Energy Board (the "Board") with a breakdown and explanation of the Business Development & Customer Strategy ("BDCS") Department's forecast capital costs for revenue generating growth opportunities for the 2014 to 2016 period. As evident from the figures presented in Table 1 (below) and Table 2 (page 9), the only such revenue generating capital expenditure budget for 2014-2016 is that of the Business Development group, and more specifically the Natural Gas for Transportation ("NGT") group.

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Customer Care	-	-	-	-
Market Development and Sales	-	-	-	-
Business Development	294	3,481	3,486	3,693
Direct Capital Subtotal	294	3,481	2,486	2,693
Total	294	3,481	3,486	3,693

2. The Business Development group is responsible for identifying, introducing and establishing energy technologies that can help the Company meet its energy efficiency objectives, or meet customers' energy demands more effectively while maintaining financial prudence. Customers benefit from these efforts through the

resulting innovations in technologies and the continued cost competitive position of natural gas relative to other fuels and technologies.

3. The NGT group has three primary functions. The first function is the provision and administration of Company NGV resources. The second function is work with stakeholders to support the growth and development of the natural gas for transportation market. The third function is to supply natural gas to the Company's customers through public and private refueling stations. The capital spending requirements detailed in this evidence relates to the third function.

4. As explained more fully below, over the 2014 to 2016 period, the NGT group plans to construct two Compressed Natural Gas ("CNG") refueling stations each year, to serve market needs. Additionally, the Company plans to expand its Vehicle Refueling Appliance ("VRA") Rental Program, to serve a broader market. The capital costs associated with these two activities account for most of the BDCS Capital Budget for 2014 to 2016 (as seen in Table 2, below).

Background

5. The NGT group does not compete against other market participants, but rather plays a facilitator role intended to raise awareness, educate, and bring customers and suppliers together. The NGT group is technology and supplier independent.

6. The Board considers NGT to be an ancillary program with regulated and unregulated components (further explained on page 7). The performance of the NGT program is subject to a program rate of return versus overall EGD rate of return test (further explained below).

7. The NGT market is on the verge of a renaissance as a result of historically low natural gas prices, the increasing importance of environmental benefits, next generation engine conversion technology and an increasing supply of original equipment manufacturer ("OEM") products. However, there is still a role for utilities to play in assisting to establish the market. The NGT group has the experience and resources necessary to advance the market and bring forward the many benefits for rate payers and society in general. This will help maintain the relevance of natural gas into the future.

8. The potential environmental and economic benefits from NGT in Ontario and across North America have never been greater. Natural gas remains the cleanest burning alternative transportation fossil fuel, providing a Greenhouse Gas ("GHG") emissions reduction of approximately 20% or more over traditional gasoline or diesel fuel. North American domestic natural gas supply is abundant, and the commodity's cost is forecasted to remain low and stable for many years. With increasing frequency, customers are inquiring about the Company's NGT services.

9. Currently, natural gas is approximately 40 per cent less expensive when compared to gasoline or diesel on an energy equivalent basis. The use of natural gas as a vehicle fuel can help reduce the cost of public services such as waste collection and transit; its use in other sectors can play a role in increasing the competitiveness of Ontario businesses by reducing transportation costs for goods.

10. Vehicle manufacturers have re-emerged in the production of natural gas fueled cars and trucks. By way of example, General Motors and the Ford Motor Company now offer light duty direct natural gas powered vehicles to their customers. Medium duty and heavy duty trucks are also now available from factory OEMs such as Freightliner, Peterbilt, Mack, and Volvo equipped to operate on compressed natural

gas. Engine technology advances by Westport Innovation and Cummins Westport are providing increased penetration into the traditional liquid fuel markets (i.e., gasoline and diesel). This provides a new market opportunity for delivery trucks, refuse trucks, and other light, medium and heavy duty vehicle applications to operate on natural gas.

11. NGT in the United States is regaining momentum, primarily driven by environmental considerations and an abundant domestic supply of low cost natural gas. In January 2013, the Obama administration extended clean vehicle tax incentives for NGT and many states continue to offer tax credits or other benefits for making the switch. Over 250 CNG and LNG retail refueling stations are being built along the United States' major trucking corridors. Refuse companies such as Waste Management and Browning-Ferris Industries are operating dozens of CNG fueled refuse trucks with many more on order. Transit authorities in cities such as New York, New Jersey, Los Angeles and many others have orders for hundreds of CNG buses. Companies such as Ryder and FedEx have ordered dozens of delivery vehicles and are poised to order more.

12. Notwithstanding the abundant domestic supply of safe, low cost natural gas, the momentum of NGT in Canada is slower than in the United States. There is currently no Federal support for NGT, and only two Provincial governments currently have environmental programs that support NGT incentives: Quebec and British Columbia. Even without incentives in Ontario, there is strong interest in NGT from some customer segments. Refuse companies such as Waste Management, Browning-Ferris Industries and Green for Life are operating dozens of CNG fueled refuse trucks in Ontario and are poised to order more. Transit authorities in municipalities such as Burlington, Vancouver and Winnipeg have orders for dozens of CNG buses, and there is potential for this to expand to communities in Enbridge's

franchise. Companies such as Ryder and FedEx are exploring NGT opportunities across Canada, and particularly in Ontario.

13. The benefits of NGT extend beyond ratepaying NGT customers. NGT customers have a high load factor with minimal seasonal variation resulting in better year-round optimization of the distribution system. Since the costs of operating the Company's distribution system are recovered through rates, adding NGT customers can put downward pressure on rates through cost dilution.

Program Description

14. The NGT program has three key functions.

15. The first function is the provision and administration of company NGT resources. This includes the design, construction and operation of company NGT facilities, and assistance with vehicle conversions. Currently, about 600 out of the Company's 800 fleet vehicles are either dedicated natural gas or bi-fuel (natural gas and gasoline). The capital costs related to this function is presented within the Facilities and General Plant Capital Budget evidence at Exhibit B2, Tab 10, Schedule 1.

16. The second function of the NGT group is to work with governments, industry associations, suppliers and other stakeholders to develop and implement comprehensive strategies and standards to guide the NGT industry towards market and financial success. This includes education, training, and sales and marketing programs intended to increase the number of CNG and LNG natural gas vehicles ("NGVs") on the road and increase natural gas utilization as a transportation fuel. These are O&M activities and as such there is no capital budget for this function for 2014-2016.

17. The third function of the NGT group is to supply natural gas to the Company's customers through public and private refueling stations. This natural gas can be used to fuel light duty vehicles (e.g., cars, trucks, vans), medium duty vehicles (e.g., maintenance vehicles, delivery trucks), heavy duty vehicles (e.g., refuse trucks) and other types of vehicles (e.g., forklifts, ice cleaning equipment). The capital costs related to this function are presented in Table 2.

18. In cases where other market participants are not able to meet the full needs of a customer, the NGT group may assist by constructing, owning and operating the NGT refueling station and renting the station to the customer. The NGT group has two rental programs that may apply: the CNG Refueling Station Rental Program and the Vehicle Refueling Appliance ("VRA") Rental Program.

19. Under the CNG Refueling Station Rental Program, the NGT group provides turnkey refueling station design, construction and service. The station is comprised of compression, storage, dispensing, and ancillary equipment (e.g., controls and instrumentation). The capital cost of the station is recovered over the contract duration through a station rental fee. The majority of service work is contracted out, and its cost is recovered as part of the rental fee.

20. The Cylinder Rental Program related to the CNG cylinders installed onboard NGVs. The program is offered to NGV customers to relieve them of the burden of regular cylinder inspections and mandatory cylinder retesting. The capital costs are recovered through the rental fee.

21. Under the VRA Rental Program, the NGT group provides the appliance, its installation and service. A VRA is a compression device that stores CNG directly onboard the vehicle in its CNG fuel tank. The capital cost of the VRA is recovered

over the contract duration through a VRA rental fee. The majority of service work is contracted out, and its cost is recovered as part of the rental fee.

22. The Board considers NGT an ancillary program, meaning it is related to but not essential to the Company's primary activities of natural gas storage, transmission and distribution. For the purposes of cost allocation and rate design, and in accordance with the terms contained in EBRO 497 (rate case for the Company's fiscal year 1999), the NGT group makes distinction between regulated and unregulated activities.

23. Regulated activities require rates to be approved by the Board. These activities include the sale of natural gas under Rate 9 (the retail rate used for public refueling stations), rates 1, 6 and 100 series (rates used for private refueling stations), the provision of the infrastructure that is required to deliver natural gas in a useable form (e.g., large scale compression equipment and vehicle refueling appliances, as used for the CNG refueling stations and the VRA rentals), and the marketing of natural gas for use as vehicle fuel. Also included is the provision and administration of Company NGT resources.

24. Unregulated activities include the NGV cylinder rental program, NGV fuel systems (i.e., the design, warehousing, and distribution of NGV conversion kits), and NGV sales (i.e., the sale of conversion kits and rental cylinders).

25. The performance of the NGT program is subject to an overall rate of return comparative test. The purpose of the test is to ensure ratepayers are not subsidizing the NGT program if it is forecast to earn less than the Company's overall allowable rate of return.

26. For comparative purposes, revenues from NGV station rentals in addition to distribution margin associated with gas volumes through NGV stations, as well as the NGT program's fully allocated costs, are used to determine the program's rate of return ("ROR"). If the ROR is less than EGD's overall allowed utility ROR, then a calculation is performed to determine what amount of additional NGV revenue would be required to make the NGV program return equivalent to the EGD overall return. That additional amount of revenue is then imputed within Utility revenue and results to ensure no ratepayer subsidy of the NGV program.

27. The Company has no plans to seek changes to the manner in which the NGT program is regulated.

28. An alternative to utility involvement in the NGT market is to allow the market to emerge organically without utility support. The downside of this approach is that the benefits to NGT consumers, other ratepayers and society as a whole will take longer to occur. The utility can and should play a role in accelerating the market and advancing these benefits in time. Through the imputed revenue scheme, there is no risk to ratepayers.

2014-2016 BDCS Capital Budget

29. The 2014-2016 O&M budget for the NGT group is consolidated within the BDCS O&M budget described in Exhibit D1, Tab 15, Schedule 1.

30. A summary of the 2014-2016 capital budgets by program type for NGT is presented in Table 2 (next page). As noted above, the NGT program costs are the only forecast capital costs within the BDCS group in the 2014 to 2016 period.

Table 2 – Capital Cost by Major Expense Type (000s)

Capital Costs	Budget Col. 1 2013	Col. 2 2014	Forecast Col. 3 2015	Col. 4 2016
Cylinder Rental Program	$ 67	$ 69	$ 71	$ 73
VRA Rental Program[1]	$ 10	$ 1,412	$ 1,415	$ 1,418
CNG Refueling Station Rental Program	$ 217	$ 2,000	$ 2,100	$ 2,202
Total	$ 294	$ 3,481	$ 3,586	$ 3,693

Notes:
1) Number and type of VRA units as well as VRA unit costs are projected to remain relatively flat for the next several years.

31. The CNG Refueling Station Rental Program is being implemented to meet market demand. Enbridge has been in discussions with a number of interested customers, who would like Enbridge to construct CNG refueling stations to supply those customers' fleets. The NGT group has been in discussions and negotiations with several medium and heavy duty fleets, and it forecasts at least two CNG refueling installations per year for the next several years. The most immediate CNG refueling station needs are within the refuse market (i.e., garbage, recycling and compost trucks). The forecast within the Capital Budget of two stations each year within the 2014 to 2016 period is a conservative estimate, based on the expressions of interest that the Company is receiving.

32. The forecast costs for the CNG Refueling Station Rental Program are $2 million per year (adjusted for inflation), plus around $70,000 per year for the associated Cylinder Rental Program.

33. The forecast costs for the CNG Refueling Station Rental Program are based on an estimate of two stations being installed each year, at a cost of $1 million each. This cost estimate is based on historic costs for materials, labour and equipment

adjusted to account for trends in the industry these stations are expected to range in cost from $750,000 to $2,000,000. The average cost is approximately $1,000,000, depending on the number of trucks being served which, in turn determines the size of the refueling station.

34. The Cylinder Rental Program costs relate to regular cylinder inspections and mandatory cylinder retesting. The costs are forecasted based on historical unit costs, the number of NGVs currently participating in the program, and the number of additional vehicles forecasted to participate in the program.

35. The NGT group has been renting VRAs to customers for close to two decades, primarily to the arena ice-cleaning and industrial forklift market segments. Going forward, the Company intends to enter into a non-exclusive marketing, sales and supply agreement with an established VRA distributor. Through this agreement, EGD will own the VRAs and charge its customers a rental fee (which includes the costs to service the appliance). Table 3 sets out the forecast costs and volume for the VRA program over 2014 to 2016. Enbridge expects that this program, inclusive of gas volumes and rental amounts, will be a positive contributor to distribution margin over the life of the assets.

2014-2016 VRA Program Costs
Table 3

Line No.	Capital Costs ($000s)	Col. 1 2013 Test Year	Col. 2 2014 Budget	Col. 3 2015 Budget	Col. 4 2016 Budget
1	Ice Cleaning Installations		40	40	40
2	Ice Cleaning VRA Unit Cost		$ 15	$ 15	$ 15
3	Ice Cleaning Sub-total		$ 600	$ 600	$ 600
4	Forklift Installations		10	10	10
5	Forklift VRA Unit Cost		$ 80	$ 80	$ 80
6	Forklift Sub-total		$ 800	$ 800	$ 800
7	Parts and Materials	$ 10	$ 12	$ 15	$ 18
8	Total	$ 10	$ 1,412	$ 1,415	$ 1,418

36. The “other revenue” associated with the Company’s NGV activities (including the NGT activities) is described in Table 4 below. These amounts are consolidated within the Company’s Other Revenue described in Exhibit C1, Tab 1, Schedule 1, Table 1.

37. Revenues are forecasted to increase such that the NGT group will achieve or exceed the allowed utility ROR by 2016. The 2014-2016 ROR forecast is described in Exhibit C3, Tab 4, Schedule 1. In years that the NGT group fails to achieve its revenue targets, the ratepayer will remain protected by the comparative rate of return test, which means that the Company will impute revenue to bring the NGV program up to the overall ROR requirement.

2014-2016 Other Revenue Budget Summary
Table 4

Line No.	Total Revenues ($millions)	Col. 1 2013 ADR Budget	Col. 2 2014 Budget	Col. 3 2015 Budget	Col. 4 2016 Budget
1	Other Revenue Budget [1]	$ 0.3	$ 0.6	$ 0.8	$ 1.1

Notes:

1 For the 2013 ADR year, were imputed revenues to be accounted for, this total would be $0.8 million as reported in EB-2012-0354, Exhibit C3, Tab 3, Schedule 1.

For 2014 and 2015, the imputed revenue amounts are less than $5,000 per year. There is no imputed revenue for 2016. See Exhibit C3, Tab 4, Schedule 1.

2014 TO 2016 INFORMATION TECHNOLOGY CAPITAL BUDGET OVERVIEW

1. This evidence is intended to perform two functions, first to provide a general overview of the Information Technology (IT) department's role within Enbridge and also to describe the capital expenditures that IT plans to make in the period from 2014 to 2016.

2. The Company's IT needs are established in response to identified process or system concerns and are designed with the objectives of meeting new business requirements, enhancing productivity, reducing risk, addressing security threats and sustaining systems availability. The response to these needs and the decision to undertake a solution is guided by these objectives:

   a. Reliability – The ability of an Application to perform the required functions over a period of time without failure
   b. Security – Underlying controls/checks in an Application that protects against threats and vulnerabilities.
   c. Availability – The probability that an Application will work as required and when required.
   d. Supportability – The ability of Application Support/Service staff to install, configure, and monitor the Application, identify exceptions and faults, isolate defects and issues that would prevent the application from functioning as expected, and provide maintenance services.
   e. Maintainability – The ease with which an Application can be maintained in order to isolate and correct defects, prevent unexpected breakdowns, maximize the Application's useful life, meet new business requirements, and make future maintenance easier.

Witnesses: T. Adesipo
B. Misra

3. The Information Technology Department is responsible for supporting all hardware, software which supports the Company's operations, and network and communications infrastructure for Enbridge. In simple terms this includes all computers, printers, software programs, and communication networks. These technologies provide the Company with the ability to execute utility operations, customer care, market development, pipeline integrity, finance, human resources, payroll, legal, government and public affairs and regulatory functions with fewer staff than otherwise would be required. In addition, the department is also responsible for planning and executing Information Technology related capital projects that align with company strategies, goals, and objectives.

4. All IT equipment is purchased rather than being leased to reduce costs. The Company's purchasing strategies include utilizing request for proposals and tenders as well as leveraging its size with the goal of purchasing equipment at preferred rates.

5. The IT Capital forecast over the three year period is developed based on the Company's IT needs. IT expenditures can be cyclical in nature with differing life spans that may extend beyond one year. The previous year's expenditures do not necessarily indicate what the current year's spend should be, particularly if major replacements or upgrades arise as part of a multi-year cycle, i.e,. every 3 years, or 4 years or 10 years.

6. A summary of these capital expenditures are set out below in Table 1:

Table 1: IT Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Business Application Upgrades	8,100	12,300	7,200	11,000
Enhancement Projects	10,700	9,000	8,000	4,500
IT Infrastructure Upgrades	9,700	8,000	12,000	12,000
Core IT Total	28,500	29,300	27,200	27,500
Work and Asset Management Solution (WAMS) Program	500	35,700	23,700	7,700
TOTAL	29,000	65,000	50,900	35,200

7. Table 1 shows that IT capital spending will increase over the 2014 to 2016 period; however, it is also notable that IT's core program is actually declining when comparing the 2013 budget to the proposed spending in 2016. The capital spending increases over the next 3 years results entirely from the need to replace Enbridge's Envision work management program with a new Enterprise Asset Management (EAM) solution which Enbridge will be calling the Work and Asset Management Solution (WAMS). Enbridge's current system has reached end-of-life and cannot be reasonably upgraded. As such, IT will need to complete design, procurement, and installation of a new work and asset management solution before 2016. This project is discussed in detail in Exhibit B2, Tab 8, Schedule 2.

8. The core initiatives and WAMS are outlined in the following sections.

Business Application Upgrades

9. The Company capital budget for Business Application Upgrades for 2013 is \$8.1 million and the capital forecasts for 2014, 2015 and 2016 are \$12.3 million, \$7.2 million and \$11.0 million respectively. An Upgrade involves acquiring and installing a newer version of a piece of software specific to particular business units or processes. These upgrades are necessary to sustain the reliability, security, availability, supportability, and maintainability of business systems and applications that are critical to the operations of Enbridge.

10. Enbridge's IT has only one business application upgrade which exceeds \$2 million for the period from 2014 to 2016, that is the CIS system upgrade. The CIS system undergoes annual upgrades, and the period between 2014 and 2016 will be no exception to that. While the Company did complete a review and analysis of all IT projects, this evidence includes more detail information about only one business application upgrade because it is the sole project which exceeds the \$2 million reporting threshold. This major project is described in greater detail in Exhibit B2, Tab 8, Schedule 2, Attachment 1.

11. CIS upgrades were contemplated as part of the September 2, 2011 Customer Care/CIS Settlement Agreement (EB-2011-0226) and cumulative upgrade expenditures remain well below the \$50 million threshold for CIS upgrades which would trigger the need for a specific application to the Board.

12. The budget for Business Application Upgrades is shown in Table 2 below. The "lumpiness" of spending in 2014 and 2015 is due to required software upgrades and

replacements driven primarily by vendor changes to software programs in order to ensure reliability, security, availability, and supportability. Exhibit B2, Tab 8, Schedule 2, Attachments 1.

Table 2 : Business Application Upgrade Spending 2013 to 2016 ($000)

	Budget	Forecast		
DESCRIPTION	**2013**	**2014**	**2015**	**2016**
CIS	4,100	6,800	4,800	6,800
Other Core Business Projects less than $2M over 3 year period	4,000	5,500	2,400	4,200
TOTAL	**8,100**	**12,300**	**7,200**	**11,000**

Enhancement Projects

13. The Company budget for Enhancement Projects in 2013 is $11.6 million and its forecasts for 2014, 20415 and 2016 are $9.0 million, $8.0 million and $4.5 million respectively as shown in Table 3 below. Enhancements are those projects that leverage existing systems to add or extend functionalities to meet the evolving needs of the departments within Enbridge. The costs of major projects exceeding $2M are summarized below and are also explained in greater detail Exhibit B2, Tab 8, Schedule 2, Attachments 2 and 3.

Table 3 : Enhancements Spending 2013 to 2016 ($000)

	Budget	Forecast		
DESCRIPTION	**2013**	**2014**	**2015**	**2016**
The Energy Transaction Reporting & Contracting (EnTRAC)	100	-	2,000	2,000
Customer Care Improvement Initiatives	1,400	6,500	4,000	1,000
Mobile Application Replacement	6,500	-	-	-
Other Enhancement Projects less than $2M over 3 year period	3,600	2,500	2,000	1,500
TOTAL	**11,600**	**9,000**	**8,000**	**4,500**

IT Base Infrastructure Upgrades

14. The Company capital budget for IT Infrastructure Upgrades for 2013 is $9.7 million and forecasts for 2014, 2015 and 2016 are $8 million, $12.0 million and $12.0 million respectively as shown below in Table 4. IT Infrastructure supports the entire organization. Examples of this include the telephone system, desktop computers and printers and required software. The forecast budgets relate to hardware and software upgrades and are necessary and must be performed as part of on-going upgrade replacement cycle to ensure that IT infrastructure's reliability, security, availability, and supportability of Enbridge operations. The costs of major projects exceeding $2M are summarized in Table 4 below and also explained in Exhibit B2, Tab 8, Schedule 2, Attachments 4,5 and 6.

Table 4 : IT Infrastructure Upgrade Spending 2013 to 2016 ($000)

	Budget	**Forecast**		
DESCRIPTION	**2013**	**2014**	**2015**	**2016**
IT Infrastructure & Productivity Services	2,800	3,000	6,000	3,800
Data Centre Operation	3,930	2,100	2,100	2,600
IT Service Management/Desktop Replacement	1,900	2,100	2,800	4,300
Other IT Infrastructure upgrades less than $2M over 3 year period	1,100	800	1,100	1,300
TOTAL	**9,730**	**8,000**	**12,000**	**12,000**

Work and Asset Management Solution (WAMS) Program

15. The WAMS Program is a program to evaluate and implement an Enterprise Asset Management (EAM) solution that will enable Enbridge to operate core functions related to Work and Asset Management into the future. The current system processes over a million work requests and plays a critical role in managing emergencies. There is a need to replace the current system due to obsolescence of underlying technologies which pose a business and technology risk.

Witnesses: T. Adesipo
B. Misra

16. The Company forecasts the need to spend $35.7 million in 2014, $23.7 million in 2015 and $7.7 million in 2016 for implementation of new WAMS solution. The WAMS program is explained in Exhibit B2, Tab 8, Schedule 2.

Business Application Upgrade – Customer Information System (CIS)

Summary

Information Technology – Business Applications group provides support to the functioning of the Customer Information System (CIS).

CIS is the key tool for the Customer Care department to manage daily interaction between Enbridge's 2 million gas distribution customers.

Annual transactions volumes are representative of servicing those 2 million customers, as shown by following statistics:

- Number of invoices in 2012 – 25.1 million
- Collection activities in 2012 – 7 million transactions (includes outbound calls, disconnections and assignment to Collection Agencies)
- Number of systems interfacing with CIS - 40
- Total number of CIS system users – 1200

To maintain the integrity of the CIS system and to exploit new functionality available from SAP, regular system upgrades are required. Annual enhancements are required such as Deferral Variance clearing and rate changes as an example. In addition, there are ongoing reporting enhancements required to assist the business in better managing the customer care services provided and enhancing them as needed. The upgrades are required to be performed every 2 years which will explain the changing costs in the table shown below.

The costs of supporting the enhancements and upgrading the CIS system are shown below in Table 1.

	Table 1: Capital Cost Total ($000)			
	2013	2014	2015	2016
Total Costs	3,852	6,800	4,800	6,800

Background

Enbridge's current CIS is based on an SAP platform and was implemented in September 2009 utilizing an unprecedented consultation process with stakeholders, leading to a highly cost-effective implementation which has performed effectively since going-live. Since the start of 2010, more than 3000 changes have been implemented, both minor and major in nature, to enhance the functionality of Enbridge's CIS. Given the size and scope of this system deployment, this level of change was expected and will be ongoing.

CIS upgrades were contemplated as part of the September 2, 2011 Customer Care/CIS Settlement Agreement (EB-2011-0226) and cumulative upgrade expenditures remain well below the $50 million threshold for CIS upgrades done between January 1, 2013 and December 31, 2018, and therefore do not initiate the need for a specific application for Board approval.

As SAP continually publishes major and minor software updates it is important that Enbridge's CIS system is maintained at a current version. There have been no upgrades to Enbridge's version of the system code and is becoming outdated. The Company will incur increased maintenance and support costs if the CIS is not upgraded in the near term. In addition, any further delay in performing this upgrade, makes the process of upgrading its CIS much more complex, increases the cost of the upgrade even more and increases the risk. Enbridge has not upgraded the CIS system since 2009 as it was involved in stabilization of the technology and the related business processes. In the future, Enbridge will be moving to a 2 year upgrade cycle as was contemplated during the software implementation. One of the key advantages of undertaking the planned upgrade in 2014 is that it will eliminate the need for the Company to continue to utilize complex customizations which are more difficult to support and maintain then the upgraded SAP standard code.

The software updates published by SAP will also provide Enbridge with new functionality or modifications to existing functionality that will help the Company become more efficient and may also be used to improve Enbridge's processes and customer experience.

Program Description

The program involves significant upgrades and enhancements to the SAP customer information system.

1. The software vendor, SAP, publishes system software updates and system support updates regularly. These updates contain code fixes which provide performance improvements for the SAP system. These software upgrades help to keep the CIS SAP software compatible with current versions, enhance productivity via performance improvements, maintain systems integrity, and also help to reduce the customizations to the core SAP software. These software updates also give Enbridge the opportunity to exploit new functionality within the current standard software.

2. Annual modification and enhancement activities include:
    i. Changes to improve customer service representative and back office billing functionality and efficiency. Yearly functional enhancements to improve functionality/capabilities for customers.
    ii. Yearly functional updates as requested by the departments using CIS including Customer Care, System Measurement, Operations and Finance

    There will be upgrades to address the needs of the business and support objectives to improve productivity, safety and reliability (e.g. meter replacements) and meet regulatory requirements (e.g. QRAM).

3. To support the business, reporting needs are regularly identified to provide accurate and real time information in the best possible formats. The reporting enhancements assist the different functions of the business by enhancing productivity and meeting regulatory requirements.

   Every year the project teams identify old and inactive data that is then archived. The archiving initiative improves Productivity and enhances the CIS system integrity.

These upgrades and enhancements are necessary at this time to maintain the integrity and currency of Enbridge's CIS system.

Capital Requirements

Table 2 below summarizes the costs that comprise the capital requirements over the forecast period for this project. This capital cost was contemplated as part of the Customer Care/CIS settlement agreement (EB-2011-0226).

	Table 2 : Capital Requirements Summary ($000)					
			Budget	Forecast		
NO	ITEM	BRIEF DESCRIPTION	2013	2014	2015	2016
1	Software Upgrades	A major upgrade is performed every 2 years and a minor update every year	1,000	3,000	1,000	3,000
2	Releases	Business required enhancement packs and repairs	2,486	3,000	3,000	3,000
3	Other	Other individual projects less than $2 million over 3 year period	366	800	800	800
		TOTAL	3,852	6,800	4,800	6,800

Witnesses: B. Misra
E. Phagoo

The Energy Transaction Reporting Accounting and Contracting (EnTRAC) Enhancement Program

Summary

Information Technology (IT) is responsible for the maintenance, enhancement and performance of Enbridge's Energy Transaction Reporting Accounting and Contracting (EnTRAC) system. EnTRAC is approaching its end of useful life since its implementation in 2003. As EnTRAC is a complex, custom Enbridge application/system, there is substantial work to ensure EnTRAC's ongoing viability and serviceability.

The main focus of the EnTRAC application is to allow Direct Purchase customers the ability to manage contracts, manage gas supply and view financial information. EnTRAC is a core Enbridge application managing over $50 million of gas transactions per month. Failure of this system would result in the inability of agents, customers and vendors to manage the financial reconciliation process, and the creation of the Invoice Remittance Statements (IRS) and Funds Imbalance Statements (FIS). Enbridge would be unable to pay the vendors (approximately $50 million/month), and also be unable to collect any potential fees (ABC, DPAC, volumetric charges). Volumetric transactions such as load balancing, title transfers, and nominations could not be conducted. This would result in further financial and gas supply implications to Enbridge.

Failure of the EnTRAC system would also result in the Company's inability to meet its obligations under the Gas Distribution Access Rule (GDAR) to all the Direct Purchase customers, which would result in non-compliance with the GDAR rule and would result in associated financial penalties

This program will satisfy the need for ongoing functional upgrades, and foundational system upgrades and enhancements to ensure the continued operability of the EnTRAC system such that Enbridge can continue to meet the evolving needs of our customers, by protecting against hardware failure and software obsolescence. These upgrades ensure that Enbridge continues to provide a high degree of self-service to its customers, effective process execution, and integrity and availability of the customer information. All this will ensure a continued high degree of customer satisfaction and regulatory compliance.

The EnTRAC enhancement program will improve the process of integration to the current CIS application. Due to the nature and the complexity of the EnTRAC system, the timeline for this integration will be a 2 year process that will result in an implementation in Q4 of 2016. The current EnTRAC system is a mature application (9 years old) and there have been several modifications in response to changes to regulatory requirements (eg. GDAR and MDV –

re-establishment project). With every modification to the EnTRAC system to address further regulatory requirements the system becomes more complex and therefore more difficult to address further regulatory and market place requirements as well as to support and maintain the existing system. To ensure the functionality, customer experience and satisfaction Enbridge is requesting that this integration proceed in 2015 and 2016.

The capital cost requirements over the forecast period are shown below in Table 1.

	Table 1: Capital Cost Total ($000)			
	Budget	Forecast		
	2013	2014	2015	2016
Total Costs	100	0	2,000	2,000

Enbridge has completed a study to replace the EnTRAC system with functionality in CIS-SAP system and the cost was estimated at $9 million. The alternative to this is to extend the life of the EnTRAC system by implementing the enhancements and work contemplated in the above forecast. This is seen as the most cost effective approach.

Background

The Energy Transaction Reporting Accounting and Contracting (EnTRAC) application/system was implemented in 2004 to provide billing functionality to Direct Purchase customers. EnTRAC was designed to develop and implement appropriate measures to address fundamental requirements that included providing a higher degree of self-service to information and process execution, improving the integrity of the information available, and its transparency, ensuring a high degree of customer satisfaction through functionalities such as:

- The main focus of the EnTRAC application is to allow Direct Purchase customers the ability to manage contracts, manage gas supply and view financial information.
  - Contracts
    - Vendors have access to manage their respective customer accounts/contracts
    - Electronic submission to add/drop, transfer customers to different price points and pools
    - Manage pools of their respective Customer Contracts

- Gas Supply
  - Provide Banked Gas Account (BGA) information, gas volumetric information
  - Ability to manage pool load balance volumes
- Financials
  - View remittances/fiscal imbalances related to the specific vendor
  - Manage customer account adjustments

EnTRAC is a critical Enbridge application managing over $50 million of gas transactions per month. Failure to deliver gas may incur a sizable monetary penalty as well as other damage to Enbridge's image and credibility.

Like every commercial software application EnTRAC requires ongoing updates and upgrades to maintain its currency, its effectiveness, and its security on an annual basis. EnTRAC was originally implemented in 2004, and has required many functional enhancements since that time. TheGDAR (Gas Distribution Access Rule) was issued in late 2002, with a further order of an Electronic Business Transaction (EBT) system issued in November of 2005. This resulted in the implementation of defined functional changes in June of 2007 to be compliant with GDAR. In addition, there were more recent Mean Daily Volume (MDV) enhancements required in response to the OEB's initiation of Order EB-2008-0106 on May 29, 2008and its subsequent Amended Decision and Order, dated Sept 21, 2009.

Program Description

The purpose of this program is to ensure the continued operability of the EnTRAC system such that Enbridge can continue to meet the evolving needs of our customers, by protecting against hardware failure and software obsolescence. The upgrades included in the program for 2014 to 2016 will ensure that Enbridge continues to provide direct purchase options and services that meet the evolving needs of the market place, as well as high self-service standards to our customers with respect to information availability and transparency. They will also support customer satisfaction objectives and ensure a continued high degree of regulatory compliance. An example would be the need to modify the application, in order to accommodate modifications to transportation service offerings

This program encompasses the need for ongoing functional upgrades, and the foundational system upgrades and enhancements. As EnTRAC is a complex, custom Enbridge application/system, there is substantial work to ensure EnTRAC's ongoing viability and serviceability.

System upgrades include:

- Enhancements to support evolving customer & market requirements
- Hardware upgrades and the associated Operating System upgrades
- Upgrades/Patches to the foundational technology
- Changes to the customizations as a result of core software upgrades.
- Enhancements to the existing functionality (reports, optimization of screens, etc).
- Validation of upstream and downstream system interfaces (other Enbridge systems that feed to, or receive from EnTRAC such as CIS – SAP).

Capital Requirements

Table 2 summarizes the costs that comprise the capital requirements over the forecast period for this program.

	Table 2 : Capital Costs Summary ($000)					
			Budget	**Forecast**		
NO	**ITEM**	**BRIEF DESCRIPTION**	**2013**	**2014**	**2015**	**2016**
1	EnTRAC	Replacement of hardware, software license with integration with CIS application.	99	150	2,000	2,000
		TOTAL	99	150	2,000	2,000

In 2013 and 2014 the costs above are primarily for the sustainment of the EnTRAC application. The increase in 2014 is to undertake a lifecycle assessment of the EnTRAC application and hardware / software. In 2015 and 2016 a major upgrade of the EnTRAC application will be implemented.

Customer Care Improvement Initiative

Summary

Information Technology (IT) – Business Applications provides critical support to the functioning of Enbridge's customer care activities in areas such as the Customer Information System (CIS), the customer service website and other customer facing technological interfaces.

Enbridge's customer care activities are central to the majority of daily interaction between Enbridge and its 2 million gas distribution customers. The customer care services provided include monthly meter reading and estimation of consumption, monthly billing and payment processing, in addition to ongoing collections and customer contact services. These customer care services are delivered to our customers through Enbridge's CIS.

Enbridge's customer care department has surveyed its customers and determined that there is a growing demand to have more efficient and accessible links to their utility and the services that the utility provides. Enbridge's goal to be responsive to their customers has led Enbridge to the identification of several IT improvements aimed at improving services to customers and customer experiences. This customer care improvements program is designed to achieve that goal through improvements such as:

- Rebuilding the Company website with a focus on enhancing the customer's self-serve capabilities;
- Enhancing the billing functionality in the CIS;
- Implementing updates to the CIS system to improve customer satisfaction as well as productivity improvements.

The capital requirements over the forecast period for the customer care improvement initiatives are shown below in Table 1. Further details are included in Table 2 that follows.

	Table 1: Capital Cost Total ($000)			
	Budget	**Forecast**		
	2013	**2014**	**2015**	**2016**
Total Costs	1,585	6,500	4,000	1,000

Background

Information Technology provides Enbridge's customer care function with IT solutions and support with such things as the CIS, website, automated telephone system, and other customer facing systems. IT works with the Customer Care department to prioritize and implement strategies necessary to enhance the customer experience and improve customer satisfaction, taking into account underlying business processes, training and change management requirements.

Industry in general has identified the ever growing importance of serving customers effectively and providing them with a positive experience with every communication that occurs. Enbridge recognizes the continuing requirement to keep customer service assets evolving by means of upgrades to maximize their effectiveness and the service goal of customer satisfaction.

Enbridge regularly surveys customers on their satisfaction with the Company and how Enbridge can improve its customer service. This research indicated that customers' expectations are increasing rapidly with the advent technological advancements. A failure to undertake these initiatives would lead to lower customer satisfaction.

One of the strategic priorities for Enbridge is to improve customer satisfaction. This includes responding to evolving customer needs on when and how customers want to communicate with the Company. For example, as customers become more comfortable with technical tools such as the internet, they expect to be able to interact with their utility in ways and at times that are more convenient to them. There has been a steady shift away from the traditional method of calling the Call Centre to leveraging online and mobile communications, including internet and smartphones. Responding to these increased customer expectations by providing enhancements to customer delivery practices is becoming an industry standard across utilities. Enbridge's current customer facing systems provide limited options for customer self-service. In addition, higher levels of customer satisfaction ensure that the Company is able to operate efficiently, doing things right the first time, lowering calls, complaints and rework.

In order to meet the changing needs of its customers, Enbridge will be continue with its website enhancements and will implement a number of initiatives to improve its customer's experience and convenience by providing customers more options in how and when they interact with Enbridge.

Program Description

The customer service enhancements that the Company will be implementing in 2014 to 2016 are as follows:

1. Rebuild the Enbridge website and enhance Customer Self Service
    - The Company recognizes that an organization should refresh its website design every 3-4 years to ensure validity of its content and services, currency of internet design features, and appropriateness of its background technologies. As Enbridge's current website was delivered in early 2011, and, as Enbridge has chosen to operate in a 4 year refresh model rather than 3, Enbridge has planned for a 2015 refresh of its website. This rebuild will address the security, reliability, availability and maintainability of the customer self-service website.
    - A key focus on the website will be the redesign of some of the content on the Enbridge website to make it easier for customers to find information and rewriting content to make it easier to understand.
    - Enhancements and additions to self-service functionality is also an area of focus, for example, Enbridge's electronic bill presentment will need to be rebuilt with the upcoming bill redesign initiative that the Company is currently undertaking. In addition, there will be enhancements to our interactive voice response system to improve our customer's experience with using tools provided by Enbridge in understanding the services Enbridge provides.
2. CIS Billing Enhancements
    - Enbridge is also going to enhance some of its billing functionality in CIS. This would include enhancements to the way CIS cancels a bill and rebills a customer to make the transaction more customer friendly. In addition, enhancements are required to the Budget Billing Program in CIS, in particular, to better handle accounts where a customer has changed gas contracts and the Company needs to review and enhance the estimation functionality in CIS to ensure it is performing as expected after 3 years on the new CIS.
3. CIS Sustainment Initiatives
    - Enbridge will continue to implement CIS updates to meet the evolving needs of the business and changes to business processes. These updates will be prioritized with a focus on improving customer satisfaction and productivity by doing things right the first time.
4. Other initiatives
    - Other initiatives include an upgrade to the Knowledge Management Tool used by the Company and its service providers when responding to customer enquiries and performing transactions in CIS. In addition, the Company will be looking at the implementation of

customer segmentation for collections purposes so that the Company will be able to tailor collections activity to specific customer behaviors, thereby improving collections performance.

The above enhancements will be managed by Enbridge using both internal and external resources.

Capital Requirements

Table 2 below summarizes the costs that comprise the capital requirements for the forecasted period for these projects.

	Table 2 : Capital Costs Summary ($000)				
		Budget	Forecast		
NO	ITEM	2013	2014	2015	2016
1	Customer Self Service and Website	1,585	3,000	1,500	500
2	CIS Billing Enhancements		1,500	1,000	
3	CIS Sustainment		500	1,000	500
4	Other		1,500	500	
	TOTAL	1,585	6,500	4,000	1,000

While Enbridge is implementing a number of initiatives to refine its customer self-service website in 2013, as noted at line item 1 in Table 2 above, a substantial portion of the costs of the work required for the 2015 website refresh will occur in 2014 with roll out of the enhancements in 2015. Cost forecasts for 2015 and 2016 include activities required to sustain the enhanced website and to sustain it going forward in 2015 and 2016.

The CIS Billing Enhancement initiative will take place after the CIS SAP upgrade beginning in 2014 and continuing into 2015. This work involves adding additional functionality in respect of the rebilling and budget billing activities of the Company. CIS Sustainment activities are those required during the forecast period to support CIS Upgrades. The forecast for Other activities includes a number of smaller planned initiatives in 2014 and 2015 including upgrades to the Knowledge Management Tool and collection process improvements.

IT Infrastructure and Productivity Services

Shared Software Licensing and Upgrades

Summary

The IT department is responsible for purchasing and maintaining a set of applications shared by all Enbridge employees. This includes the Microsoft package of applications (Word, Excel, Powerpoint, and Outlook email, Lync, Sharepoint, etc), the application for managing the day-to-day activities on the Enbridge website and reporting and analytics tools. The maintenance this up-to-date information technology set in order to avoid software incompatibilities, system failures and security breaches primarily by performing regular upgrades and enhancements.

The capital requirement included in this evidence is specific to the applications and databases that support applications that perform that following functions such as:

- Financial systems
- Interface between Enbridge and Extended Alliance
- Microsoft licenses (Word, Excel, Powerpoint, Outlook, Exchange, Lync, Sharepoint, etc)
- Extranet technologies, such as Tridion, used to create our website
- Reporting and management tools like SAP Business Warehouse

Table 1 below shows the summary level Capital Requirements for this program for 2014 to 2016 and also shows the 2013 Budget amount. A detailed breakdown is included in Table 2.

Table 1: Capital Requirement Summary ($000)

		Budget	**Forecast**		
Item	**Brief Description**	**2013**	**2014**	**2015**	**2016**
TOTAL	Software & Licenses	**2,800**	**3,000**	**6,000**	**3,800**

Background

The program described in this exhibit is an ongoing business program based on Company historic practices and policies. The approaches followed by Enbridge are based upon accepted industry standards.

This program, which refers to the Microsoft Productivity Suite, the database application servers, the website and the data mining is principally focused on periodic, strategic upgrades and interim period enhancements of Enbridge's enterprise systems. It also includes the development of an integration strategy which refers specifically to getting applications to work well together and leverage data that can be shared across applications such as customer information, primarily driven by :

- the company and vendor standard of a 3 – 5 year product life schedule,
- the new and increasing organizational demand for real-time information,
- need for real-time visibility into business activities and processes,
- Standards-based business to business protocols which allows us to share information through applications with 3rd parties, alliance partners and contractors

Enbridge is required to purchase the rights to use any software used by all employees. While Enbridge has had long standing agreements every time a licensing renewal comes due the Company looks at various options including going to tender and looking at financials and vendor offerings before making any final decisions.

The Microsoft upgrades are done on a company wide basis every 3 to 5 years and impacts all 3000 users at Enbridge. The lumpiness of spend is attributed these upgrades. Enbridge maintains a very secure and reliable environment by ensuring that it maintains all hardware and software, and keeps the software current with the latest security patches.

Enbridge is guided by the vendor recommendations with respect to the nature and timing of upgrades and enhancements, thus mitigating the risk of extended outages to any of Enbridge critical applications and the serious consequences of such an event. System failures could impact the productivity of thousands of employees as well as their abilities to serve customers.

In supporting this infrastructure and associated applications, IT follows standard protocol for management, maintenance, replacement and upgrading of the infrastructure in order to achieve reliability, security, availability, supportability, and maintainability of business systems and applications. From a management perspective this includes constant monitoring of all systems using both manual and third party monitoring processes such as the client vantage software tool which manages and reports on server and application availability and up and down time.

Program Description

This on-going program is aimed at keeping all critical software and maintained and working at peak levels to ensure that day-to-day business operations can be conducted without system failure.

The Company ensures that it reviews all options when considering software upgrades, these options include:

1. Upgrade per vendor requirements, but ensure that negotiations are completed for best possible terms.

2. Move to a new product that will provide the same functionality as the old.

3. Do nothing and run the risk of systems failures.

In most cases, Enbridge finds that option 1 which is a negotiated upgrade with the existing vendor is the most cost effective approach and the one that causes least disruption to important Enbridge business systems.

During this forecast period, the program will address:

- Microsoft Enterprise Agreement Costs
- Microsoft Office Product upgrades
- Microsoft Mail and Calendaring upgrades
- Microsoft Lync upgrades
- Microsoft Sharepoint upgrades
- Oracle database software upgrades
- Upgrades to website management software
- Reporting and analytics software upgrade

Capital Requirements

Table 2 below shows the more detailed Capital Requirement for 2014, 2015 and 2016 as well as the 2013 budget.

Table 2: Capital Requirement ($000)						
			Budget	Forecast		
N0	Item	DESCRIPTION	2013	2014	2015	2016
1	Microsoft License	Licensing cost for Microsoft Office and other Microsoft related products as well as upgrades	1,400	1,500	3,000	1,800
2	Application database software (Oracle)	Database upgrades for applications used by all employees	598	400	1,500	1,100
3	Others	Other projects less than $2.0M over 3 years period	632	1,100	1,500	900
		TOTAL	2,600	3,000	6,000	3,800

Data Centre Operation (IT Infrastructure Upgrade)

Summary

Enbridge has two data centres: one at Victoria Park Centre and the other Thorold. These data centres house the infrastructure and applications that are used by the Company and its customers, employees and contractors on a daily basis. Many of the business applications hosted in the data centres are critical to the business such as email, CIS (Customer Information System, which is the system that is used to provide customer care and billing) and GIS (Geographical Information System, which is used to provide asset information, such as the location of the company's pipes in the ground).

The Information Technology (IT), Data Centre Operations group manages the data centres and all of their hardware as well as the physical environment including air conditioning, and specialized furniture such as racking for equipment.

The capital requirements for this program at a high level are needed to:

- replace end of life data centre Infrastructure (data centre end of life projects)
- provide additional infrastructure capacity to meet annual growth in applications, data storage requirements, specialized shelving and racks, etc. (Annual data centre infrastructure growth projects)

Table 1 below shows the total capital requirement for the data centres and includes forecasts for 2014 to 2016, as well as Enbridge's 2013 budget. A more detailed breakdown is shown later in Table 2.

Table 1: Capital Requirement Summary ($000)						
			Budget	**Forecast**		
	Item	**Brief Description**	**2013**	**2014**	**2015**	**2016**
	TOTAL	Data Centre Operation - IT	**3,930**	**2,100**	**2,100**	**2,600**

Background

All businesses today (except for the very small) depend upon network technology to connect multiple users and their various laptops and desktop computers together, to allow for inter-company communications and shared use of devices such as printers. Most business (certainly all large ones) take sharing much further to include the shared use of software, data storage, central processing equipment by multiple users in multiple locations. Centralizing infrastructure into large data centres is industry standard for large enterprises as it is the most economical and secure way to provide those services. Enbridge falls into this category and operates two data centres in Ontario: one at its head office (the Victoria Park Data Centre) and the other in Thorold, Ontario (the Thorold Data Centre).

The Data Centre Operations Infrastructure Program is an ongoing program similar to that managed by all other large enterprises, and is required to maintain all the Enbridge applications and data. Data centre infrastructure is made up of components that have a life expectancy of 4 to 5 years. While the industry standard is to replace infrastructure in the 3-4 year timeframe, Enbridge purchases its data centre IT equipment with a 4 year warranty and then commences replacing it in the 4th or 5th year. Enbridge's conservative approach of extending infrastructure past the 4th or 5th years is economical for the company, but stretching it past that timeframe will lead to unacceptable failure rates and increased costs. A failures of data centre infrastructure would result in application unavailability resulting in loss of employee productivity, customer dissatisfaction and/or data loss.

Some may have experienced, but all can imagine, the chaos in an office when a main server goes down, work stops, hours of effort are lost, and often connections to colleagues, customers and suppliers are terminated. To provide reliable infrastructure service, hardware must be replaced based on life expectancy.

The other category of spending in this program is infrastructure required to address growth. This is primarily growth in data storage capacity, but also includes the need for additional servers to manage an ever growing list of applications, as well as applications that are growing in terms of what they do for users.

Enbridge's projects that are replacing end of life data centre infrastructure and projects that are purchasing infrastructure to meet the annual data centre infrastructure growth are listed and described below.

The projects over the three years will add annual capacity or replace end of life infrastructure as per industry standards; which is to say, replace hardware in the 4th or 5th year of use in order to avoid increasing and lengthy outages to critical applications and services due to hardware failures.

Program Description

The Data Centre Operations Program is a 3 year $6.8 million undertaking. A detailed description of each project in the Program is listed below.

1) Data Centre Infrastructure End of Life Projects

***Backup & Recovery Infrastructure*:**
Data is created by software applications and end users. Examples would include email, spreadsheets, documents and databases. All this data needs to be "backed up" to provide a copy if someone accidentally deletes the data or there is a server or data centre failure. Everyday more and more data is being created so Enbridge must increase the capacity of its backup and recovery infrastructure each year to meet the demand. When the Company's infrastructure reaches end of life it must be replaced or run the risk of unplanned downtime and lost data. The Industry standard to replace this critical infrastructure is 4 years. Capital is required to replace the data centre end of life "backup and recovery" infrastructure in 2014 and to meet the annual growth of data in 2015 and 2016.

Server Refresh:

Figure 1: Servers

A server is a piece of hardware installed in the data centre (***see Figure 1***). Servers can have software applications installed on them used by end users (email, CIS, GIS etc...) or they can provide access to services for end users (Internet, Printing, Spreadsheets, Word Documents etc...) Capital dollars are required to replace the 35 – 55 servers that are end of life each year. Industry standard suggests a 3-4 year replacement cycle for servers. Enbridge has a 4 year replacement cycle. Enbridge purchases servers with a 4 year warranty with a plan to replace in the 4th year. Failure to replace servers within a consistent lifecycle will lead to server failures. When servers fail applications are no longer available to end users.

Data Switch Replacement:
Data switches provide the connection for all computers and telephone equipment from the user's office to the application servers and SAN storage installed in the Data Centres. Industry standards dictate that switches be replaced every 4-5 years before hardware failures occur and outages to the critical network

are encountered. Enbridge's conservative approach of extending infrastructure past the 5^{th} or 6^{th} years is economical for the company, but stretching it past that timeframe will lead to unacceptable failure rates and increased costs. If data switches fail end users are not able to access applications or use their desktop phones. Capital is required to replace 80-100 data closet switches in 2016 due to the technology reaching 5-6 years of usage.

2) Annual Data Centre Infrastructure Growth Projects

Data Centre Equipment:

Capital for data centre Infrastructure is used to add data centre equipment to meet the annual growth.

Figure 2: Rack

Capital dollars would be spent on items such as:

- **Racks – (see figure 2)** Infrastructure is installed in specialized racks in the data centres. When more servers are purchased at some point the company will have to purchase a rack. A rack holds many infrastructure components. On average the company purchase 5-10 racks annually.

- **PDU's** - PDU's are power bars that are installed in the racks. Infrastructure is plugged into the power bars to access power. On average the company purchases 10-20 PDU's annually

- **Cabling** - New cabling is required in the data centre to connect infrastructure to the network so end users can access the applications and services required to perform their job duties.

Data Centre Environmentals:

Capital for the data centre environmental project will be used to purchase equipment to meet the annual growth of the data centres and replace end of life infrastructure in 2016. This would include large items such as:

Figure 3: UPS

- **UPS & Batteries – (see figure 3)** The Uninterruptible Power Supply ("UPS) is equipment that maintains power to the data centre infrastructure while the generator starts up and provides power. Without the UPS when there is a power interruption servers shutdown.

- **Air Conditioning – (see figure 4)** Air conditioning units are required to provide cooling in the data centre to maintain a suitable temperature for the infrastructure to operate.

  The infrastructure creates a great deal of heat. If the infrastructure gets to hot it will fail. These units are installed inside the data centres and are not related to the main building air conditioners.

Figure 4: Air Conditioner

Figure 5: Remote Power Panel

- **Remote Power Panels – (see figure 5)** Remote power panels are electrical panels installed within the data centre that are used to distribute power to the infrastructure.

Storage Area Network (SAN) Disk: **(see figure 6)**

Everyday more and more data is being created so Enbridge must increase the capacity of the storage area network disk to meet the demand. All the data that is created with applications such as CIS, email or GIS is stored on a SAN disk. In late 2012 Enbridge replaced the end of life SAN disk with a new SAN disk solution and purchased enough capacity for 2013. Forecasts for 2014 to 2016 include funds required to meet the annual growth

Figure 6: Storage Area Network Disk

foreseen at that time (20-40 terabytes annually). If Enbridge does not purchase additional capacity each year there will not be sufficient capacity to safely save end user or application data.

<u>Server Upgrades:</u>
Capital is required to add incremental computing hardware to servers to help with application performance. Example: A server is purchased and an application is installed. Over the lifecycle of the server there are situations when due to increased usage the application performance can slow down. To increase performance we add some additional memory or processing power to the server.

Capital Requirements

Table 2 below shows the projected capital requirements for data centre infrastructure for the forecast years 2014 to 2016, and the 2013 Budget.

These are business as usual activities and are consistent with industry standards, as well as the strategies and policies that Enbridge has employed for a number of years. The difference in the funding in each year is reflective of different components reaching end of life in different years.

Table 2: Capital Requirements ($000)

No	Item	Description	Budget	Forecast		
		Projects	**2013**	**2014**	**2015**	**2016**
1	**Data Centre Infrastructure End Of Life Projects**	• Backup & Recovery Infrastructure • Server Refresh • Data Switch Replacement	3,625	1,525	1,325	1,600
2	**Annual Data Centre Infrastructure Growth Projects**	• Data Centre Infrastructure • Data Centre Equipment • Storage Area Network (SAN) Disk • Server Upgrades	305	575	775	1,000
	TOTAL		**3,930**	**2,100**	**2,100**	**2,600**

Changes in Data Centre Infrastructure End of Life Projects 2013 - 2016

There is a $2 million reduction in 2014 from 2013. In 2013 Enbridge's CIS infrastructure was end of life and was replaced at a cost of $3.375 million. In the following years the "end of life" replacement projects are much lower. The business drives any new large applications that require infrastructure be installed into the data centres. As a result there can be peak and valleys for the end of life replacement capital required.

Changes in Annual Data Centre Infrastructure Growth Projects 2013 - 2016

The capital spent in 2013 was lower than normal. This was due in part due to a purchase in late 2012 which replaced the end of life Storage Area Network (SAN) Disk. At that time Enbridge purchased enough capacity until 2014 so no funding is budgeted for Storage Area Network (SAN) disk growth in 2013. In 2014 we will again be purchasing additional SAN disk in our annual growth projects.

In 2014 Enbridge will be replacing the end of life backup and recovery Infrastructure. Enbridge will purchase enough capacity to meet the growth for 2014. In 2015 additional backup and recovery infrastructure will be purchased to meet the annual growth again.

In 2016 the capital requirement increase is due mainly to two projects. Enbridge will be 3 years into the CIS infrastructure replacement and plans to purchase additional infrastructure for that critical application. Also in 2016 Enbridge anticipates the need to replace and add additional power and cooling infrastructure in our data centres due to the increase in server and storage hardware from 2013 to 2016.

IT Desktop and Device Replacement

Summary

Information Technology (IT) defines and delivers to the end users the appropriate computing devices and software applications they require to perform job duties. During the 2014 to 2016 period, Company devices will need to be replaced as they reach their end of life. This evidence outlines the program and the capital requirement for the replacement of these devices and the initiation of a formal company-wide laptop and desktop replacement initiative beginning in 2016.

The program provides for replacements of the various mobile, printing and fax devices in use at Enbridge: mobile hardware such as field devices (computing devices used by outside field workers to access applications where they receive their work orders and requests), handheld GPS devices (used by field staff for the accurate locating of mains and services), warehouse barcode scanners, leak survey devices (used by leak inspectors to detect leaks in our franchise area) and printing hardware such as department multifunction devices (e.g. print, fax, scan).

The capital requirement for the program through the forecast period is identified in Table 1 below.

Table 1: Capital Cost Summary ($000)				
Description	**Budget**	**Forecast**		
Desktop Replacement	**2013**	**2014**	**2015**	**2016**
TOTAL	1,925	2,100	2,600	4,300

Background

Industry standards are that desktops and laptop computing devices should be replaced every three to four years. This is based on an evaluation of not only the cost to repair older units and the impact to business functionality when the equipment fails, but takes into account the reduced cost of new equipment, increased functionality and processing speed, power conservation capabilities and other hardware enhancements that vendors add as time goes on.

Enbridge's strategy of replacing desktops and laptops every four to five years; which includes all associated peripherals such as keyboards, monitors and docking stations is a more conservative approach. After this point, the devices will need to be replaced. Historically the Company has negotiated better pricing through a buy strategy hence, all equipment is purchased and not leased. This also reduces the impact on operating costs. As part of the replacement process, every 4 years Enbridge conducts an RFQ process to select our hardware supplier for all laptops and desktops. The RFQ is created based on the Company's functional needs and pricing requirements; this process may result in Enbridge changing suppliers.

The capital requirement supports a business as usual activity, and follows a strategy that has been successful in previous years. Enbridge typically replaces in excess of 1000 devices annually. An alternative is to have longer replacement cycles, which would lead to increased hardware failures, increased operating expenses for repairs, and lost employee productivity.

Program Description

The program to replace computing devices is a 3 year and $9.0 million undertaking. A detailed description of each project in the program is listed below.

Desktop/Laptop Replacement

- The capital requirement for 2014 and 2015 reflects the replacement of computing devices that are end of life and out of warranty, and are an extension of an overall strategy initially undertaken in previous years.
- The 2016 capital requirement reflects the initiation of the next replacement cycle, including the RFQ process, which occurs every four to five years.

IT Support Requests

- The program requires the purchase of desktop peripherals, communications equipment, mobile devices, audio/visual equipment, etc.; essentially all approved miscellaneous hardware and software requests to address specific needs of the company.

Multi-Functional Devices

- The capital requirement for the program reflects the cost to replace multi-functional devices that are end of life and out of warranty. This includes multi-functional print devices, and a number of the field devices described earlier

Capital Requirements

The capital requirement for the overall program and the individual projects within it are detailed in Table 2 below.

Table 2: Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
Desktop/Laptop Replacement	1,100	650	650	1,800
IT Requests	750	750	750	800
Multi-Functional Devices (printing, fax, scanning, field devices)	75	700	1,200	1,700
TOTAL	1,925	2,100	2,600	4,300

The desktop/laptop replacement capital requirement in 2016 reflects the initiation of the next refresh cycle for the company desktops and laptops, which historically has occurred every 4 to 5 years. In other years, as devices come off warranty, they are replaced with new devices in order to avoid costly device failures as part of the replacement cycle started in a previous year.

There are 3500 desktops and laptops deployed for Enbridge employees and contrators. The latest replacement program began in 2012 which included an operating system upgrade. The breakdown of replacement by year is typically 40% in the first year and 20% for the following three years as the warranties expire. This means that the 2016 capital requirement will be larger as the next replacement cycle begins and more devices are replaced in the first year; which includes project initiation requirements such as configuration and operating system builds for the specific hardware.

IT Requests remains fairly flat each year. The funding amount is based on reviewing many years of actual spend.

Starting in 2014 a number of field and multi-functional devices are approaching end of life. In 2014 and 2015, it is primarily multifunction printing devices. In 2016 Enbridge will require the replacement of a greater number of field devices (e.g. mobile hardware, handheld GPS devices etc.); this is why there is a large increase in capital requirements in 2016.

There are 750 multifunction devices, printers and scanners deployed for Enbridge staff that is either off warranty or coming off warranty prior to 2014. The cost of servicing these types of devices increases the operating expense if not replaced. The refresh cycle includes the acquisition of hardware, deployment including testing, configuration and labour to deploy hardware. The breakdown of replacement during 2014-2016 will be approximately 30% in the first and second year and 40% for 2016 as Enbridge takes a conservative replacement approach.

Field devices (e.g. GPS and ruggedized laptops used by field workers for work management) will be coming off warranty beginning 2015 and Enbridge will again take a conservative approach in the replacement strategy. There are approximately 600 of these devices that will need to be replaced beginning in 2016. The replacement cycle includes the acquisition of hardware, deployment including testing, configuration and labour to deploy hardware.

IT Projects Under $ 2 million Over the Forecast Period 2014 to 2016:

Table 1: IT – Projects Under $ 2 million ($000)			
Description	Forecast		
	2014	2015	2016
Altra GMS / SCADA / GDMS	300	300	300
Capital and O&M Analytics Upgrade	200	400	400
COMMS	300	600	600
Datapak / iViewer	200		
EDMS	200	-	-
EHS	100	-	100
eInvoice	100	100	100
eLMS	200	-	-
EnMAR	100	100	100
Enterprise GIS	500	500	500
ESM / SRM	400	400	1,000
Extranet	-	-	-
Gas Molecule	1,000	300	200
Gas Storage - GIS	1,000	200	200
Integrated Training Environment	200	-	-
IT Risk Management	400	400	900
Lakeside Services GPS	150	100	150
MVRS	900	300	-
Network Services	400	900	400
ORM - Facilities Integrity Software	200	100	
ORM - IDP: IVE Continuation Project	200	200	50

ORM - Knowledge Management	1,100	500	200
ORM - Leak Survey Management System Replacement	350	100	100
ORMs Projects	-	-	-
RAVE	300	200	200
STB - Best Customers Initiatives	-	-	-
Sustainment	-	-	1,500
	8,800	**5,700**	**7,000**

Work and Asset Management Solution Program

Summary

1. The Work and Asset Management Solution ("WAMS") Program includes the evaluation of alternatives, procurement and implementation of a new integrated work and asset management solution. The WAMS Program will enable the Company to continue to operate primary functions into the future. It will become the primary system for creating and tracking work requests and transactional asset information related to functions such as construction, maintenance, service. WAMS will provide data that will contribute to tracking required for productivity monitoring. WAMS will also be accessed by groups such as Customer Care to respond to customer calls that relate to current and scheduled work. Furthermore, it will interface with other systems that store data required to conduct work and track related asset information.

2. WAMS is just one component of the broader Information Technology (IT) infrastructure which includes other existing systems (e.g., CIS, financial and GIS) and future systems (e.g., leak survey, asset investment planning and asset risk management) and forms part of a broader business and technology roadmap. Enbridge will mitigate significant technology risks and be in a position to make prudent decisions about related technologies in the future, by implementing the WAMS Program. Once Enbridge selects the specific replacement technology, Enbridge will be in a better position to optimize and leverage future technologies such as asset investment planning and asset risk management.

3. In April 2003, Enbridge entered into a multi-year capital project service agreement with Accenture to provide work and asset management services which supported

the Company's construction, maintenance, and service activities. To provide the services under the agreement, Accenture used work and asset management hardware and software ("Existing Technology"). This agreement expires April 1, 2014. Enbridge has made the decision for the longer term to provide similar services internally. This approach is a more cost effective solution.

4. Enbridge expects to have WAMS Go-Live December 2015. In the interim period from April 2014 to the implementation of WAMS, Enbridge intends to extend the work and asset management services with Accenture and maintain the same Board approved treatment for these services from Settlement Agreement RP-2003-0203. Enbridge is currently in negotiations with Accenture for the extension. Enbridge believes that this will continue to maintain an effective solution in the short term. This approach also assists in reducing transitional and operational risks and will maintain the current level of work and asset management services through the transition period.

5. Initiatives like the WAMS Program are infrequent. As a result, this represents a significant increase to Information Technology (IT) spending compared to typical years. Forecasted costs during 2014, 2015 and 2016 related to the WAMS Program are outlined in Exhibit B2, Tab 6, Schedule 2 (page 1) and replicated in Table 1 below. Activities in 2013 are largely preparatory for the WAMS Program and costs are lower than the other years. The capital cost in 2014 is greater than 2013 due to the need for the majority of technology purchases and detailed design to be done in that year. In 2015, spending is allocated to the configuration, testing and deployment. Activities in 2016 relate to the warranty, stabilization period and

program close-out activities. Based on forecasted activities, $59.9 million will close to rate base in 2015 and $7.7 million in 2016.

Table 1: Capital Cost Summary ($000)				
	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
WAMS Program	500	35,700	23,700	7,700
TOTAL	500	35,700	23,700	7,700

6. The process for procuring the new system and associated services will employ a competitive bid process. For this reason, details that have the potential to prejudice the bid process have not been included in this evidence. The proposed budget for the WAMS Program is based on best available information and several inputs were used including diligent inquiries with utilities in North America on similar initiatives, system vendors, system integrators and industry experts. Sync Energy has been retained to provide an independent expert review of the WAMS Program. Sync Energy has more than 23 years of experience in the electric and gas utility industry, including EAM related projects. Please refer to Exhibit B2, Tab 6, Schedule 2, Attachment for the Sync Energy Report outlining the third party review of the WAMS Program and the reasonableness of the proposed budget, schedule and approach. The Company is confident in the cost estimate based on best available information, and a few milestones will assist in reconfirming this budget. One such milestone is the system vendor / system integrator RFP that is scheduled to be completed in fall 2013. This milestone will occur after the Company has filed its evidence with the Board. The Company intends to update any relevant information to the Board once it is available.

7. A program of this magnitude takes significant time to plan and execute effectively. A diagram showing the timeline is included in the WAMS Program Description section below. In order to meet the 2015 "Go Live" date, significant activities need to occur in advance of that date. The schedule developed and proposed by the Company aligns well with other similar implementations in the industry.

Background

8. In April 2003, Enbridge entered into a multi-year capital project service agreement with Accenture to provide work and asset management services which supported the Company's construction, maintenance, and service activities. To provide the services under the agreement, Accenture used work and asset management hardware and software ("Existing Technology"). This agreement expires April 1, 2014. Enbridge has made the decision for the longer term to provide similar services internally. This approach is a more cost effective solution.

9. Enbridge expects to have WAMS Go-Live December 2015. In the interim period from April 2014 to the implementation of WAMS, Enbridge intends to extend the work and asset management services with Accenture and maintain the same Board approved treatment for these services from Settlement Agreement RP-2003-0203. Enbridge is currently in negotiations with Accenture for the extension. Enbridge believes that this will continue to maintain an effective solution in the short term. This approach also assists in reducing transitional and operational risks and will maintain the current level of work and asset management services through the transition period.

10. As part of Enbridge's consideration of undertaking the services internally it necessarily had to assess the viability of the Existing Technology to support the long term needs. For the longer term, the Existing Technology is problematic because it is based on an operating system (Windows Server 2003) that will no longer be software vendor supported after 2015 and because other critical software would similarly be losing support in the near term. Furthermore, the Existing Technology cannot be practically upgraded to the next version, Windows Server 2008.

11. Utilizing systems that are not Windows supported provides an unacceptable security risk to online attacks and other threats to the Company network. Enbridge currently receives on average 1 million external attacks per month. The Existing Technology is interfaced to many other key systems (e.g., CIS, Oracle), providing additional risk since having one system compromised, also compromises the other systems that interface. If a vulnerable component is attacked and the damage spread to other system components, resulting failures could force movement to manual processes and in many cases could prevent critical Company functions (e.g., customer billing). Current staffing levels and protocols at Enbridge are not aligned to operate on this type of manual basis for more than a very short period of time. This scenario could result in focusing on emergency only functions and delaying other non-emergency related work. In short, Enbridge cannot risk operating an unprotected system within its enterprise network.

12. In an effort to assess the long term technology needs for WAMS, the Company considered a number of options which are discussed later in the WAMS Program Description.

13. The Company has been receiving services from Accenture which has utilized the Existing Technology as a primary operational system. The Existing Technology supports approximately one million work requests every year and stores asset records associated with servicing approximately two million customers. Over 1,000 people use the related data, processes and technologies. The Existing Technology is a fundamental business tool and is foundational to providing safe and reliable service to our utility customers.

14. The principal functions of the Existing Technology include:
    - Creating work related to primary functions such as construction, maintenance, service, etc. (includes compatible units for material, time and labour)
    - Scheduling and coordinating work (includes responding to related customer inquiries and emergency requests)
    - Completing work and asset records related to that work
    - Assisting in program planning related to areas such as Leak Survey or government inspection programs for meters
    - Providing a key source of data for forecasting, workload planning, asset planning, etc.
    - Providing a source for performance measurement related to work and asset management activities

    A new integrated EAM solution will provide this functionality and more.

15. The primary components of the Existing Technology are Severn Trent Operational Resource Management System ("STORMS") v.3.5.2, iScheduler, and Pipeline

Mains Tracking System ("PMTS"), currently branded as Optimain Asset Compliance Management ("Optimain ACM"). These systems are not certified to operate on the latest software vendor supported versions of the underlying Windows Server operating systems and Oracle database. Windows Server 2003 is at the end of life and Microsoft has announced that support will expire in 2015. After that time security patches will no longer be available.

16. Enbridge is the last utility using STORMS ver. 3.5.2 and there is no practical upgrade path to the vendor's current EAM product "ARMS" since it is based on a different technology platform. CGI (Logica) is the current owner of the former STORMS product suite. Their new EAM product "ARMS" will be assessed among the other EAM products available in the market as part of this competitive bid process.

17. Over the past decade, industry practice has evolved with similar utilities moving to Enterprise Asset Management (EAM) systems that provide integrated work and asset management functionality. EAM is a common industry term that relates to the integrated work and asset management system. A more integrated solution requires fewer interfaces and reduces system complexity. The Existing Technology is not an integrated EAM system nor can it be practically upgraded to be one.

<u>WAMS Program Description</u>

18. The Work and Asset Management Solution ("WAMS") Program includes the evaluation of alternatives, procurement and implementation of a new integrated work and asset management solution. The WAMS Program will enable the Company to continue to operate primary functions into the future. WAMS will be the

primary system for creating and tracking work requests and transactional asset information related to functions such as construction, maintenance, service. WAMS will provide data that will contribute to tracking required for productivity monitoring. WAMS will also be accessed by groups such as Customer Care to respond to customer calls that relate to current and scheduled work. Furthermore, it will interface with other systems that store data required to conduct work and track related asset information.

19. WAMS is just one component of the broader Information Technology ("IT") infrastructure which includes other existing systems (e.g., CIS, financial and GIS) and future systems (e.g., leak survey, asset investment planning and asset risk management) and forms part of a broader business and technology roadmap. Enbridge will mitigate significant technology risks and be in a position to make prudent decisions about related technologies in the future, by implementing the WAMS Program. Once Enbridge selects the specific replacement technology, Enbridge will be in a better position to optimize and leverage future technologies such as asset investment planning and asset risk management.

20. At the time the Existing Technology was implemented, asset management was secondary to work management in the product offerings. Today, asset management is better understood and has risen to a much higher priority and as such, EAM products provide a better balance for both work management and asset management. This aligns with the industry trend and asset related focus at Enbridge. The EAM system will provide a foundation for Enbridge to provide its day-to-day utility services and support other requirements (e.g., safety, integrity and asset planning). The EAM solution will also provide a vendor supported product

that aligns with current underlying technology platforms (e.g., Windows Operating Systems), controlling the overall business and technology risks.

21. Below are the criteria that are used to assess Enbridge's IT infrastructure. These criteria have been applied to assess the WAMS Program and alternatives to the WAMS Program.
    a) Reliability – The ability of an Application to perform the required functions over a period of time without failure
    b) Security – Underlying controls/checks in an Application and operating system that protects against vulnerabilities through flaws in the design, development, deployment, upgrade, or maintenance and external attack.
    c) Availability – The probability that an Application will work as required and when required.
    d) Supportability – The ability of Application Support, Service and Vendor are able to install, configure, and monitor the Application, identify exceptions and faults, isolate defects and issues that would prevent the application from functioning as expected, and provide maintenance services.
    e) Maintainability – The ease with which an Application can be maintained in order to isolate and correct defects, prevent unexpected breakdowns, maximize the Application's useful life, meet new business requirements, and make future maintenance and upgrades easier.

22. As outlined later in this Exhibit, the WAMS Program will provide the best solution in satisfying these criteria.

23. EAM will be a foundational system for work and asset management, and it will be a primary source for that data. This includes performance data related to work and asset management, but is also a key source for data that will be used in assembling and optimizing the Company's Asset Plan.

24. While WAMS will provide the primary system related to work and asset management, there are a number of supplemental initiatives planned that relate to the collection and consolidation of additional asset data that integrate or will integrate into WAMS to deliver a more cohesive asset management structure. Other initiatives such as the MOP (Maximum Operating Pressure) project and DRM (Distribution Records Management) program are primarily focused on harvesting the asset data from historical paper records and other scanned documents. These individual initiatives are aligned and coordinated to ensure that there is consistent governance, standards, processes and technology and that there is no duplication of activities or costs. Figure 1 illustrates the connections between an EAM system and the types of Enbridge systems that will be leveraged to achieve the goals outlined in the DRM and MOP initiatives.

Figure 1: EAM Context Diagram

The Maximum Operating Pressure (MOP) initiative will harvest critical Asset information from paper records, new data items and other historical repositories related to MOP. The data items will be maintained in a temporary location until the data migration phase of WAM's project.

Some data will be combined and migrated with the other data elements to create a comprehensive view of the an asset that will be defined in the new EAM solution.

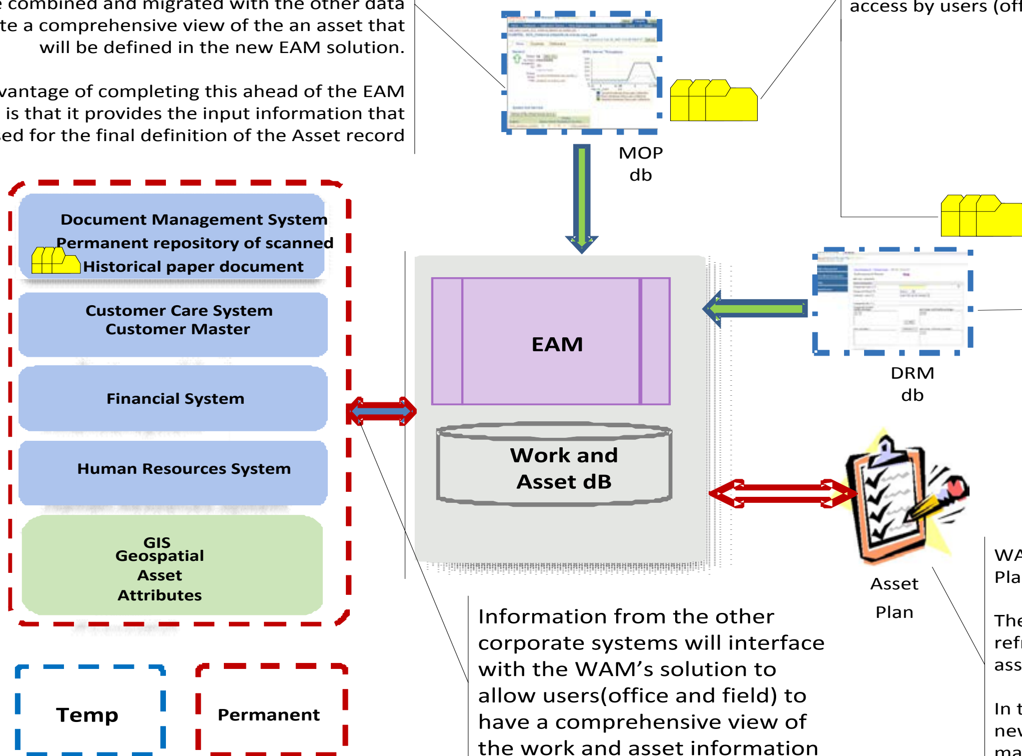
The advantage of completing this ahead of the EAM implementation is that it provides the input information that will be used for the final definition of the Asset record

The historical paper records will be moved to the Document Management System with link to the Asset records for later access by users (office and field)

The Distribution Records Management initiative will harvest critical Asset information from paper records, new data elements and other historical repositories related to the Distribution Network.

Some of the data items will be maintained in a temporary location until the data migration phase of the WAM's project. This data will be combined and migrated with the other data elements to create a comprehensive view of the asset that will be defined in the new EAM solution.

The advantage of completing this ahead of the EAM implementation is that it provides the input information that will be used for the final definition of the Asset record.



Information from the other corporate systems will interface with the WAM's solution to allow users(office and field) to have a comprehensive view of the work and asset information

WAMS will use the direction and plans in the Asset Plan to execute the work activities .

The Asset Plan is a living process that will be refreshed on a regular basis reflecting any revised asset maintenance requirements

In the future the Asset Plan in conjunction with the new WAMS will be used for other asset management functions such as Asset Investment Planning (AIP)

25. The WAMS Program includes all elements required to ensure that the EAM selected will deliver the functions required to run critical activities. The Program includes data preparation and transfer, hardware and software for the EAM solution, stakeholder readiness, process review and compliance, training and execution related to successful use of the EAM solution.

Alternatives considered for the Existing Technology

26. Several alternatives were considered that resulted in the recommendation to proceed with the replacement of the Existing Technology. These include:
    1. Do nothing
    2. Upgrade current software to most recent supported version
    3. Reconstruct current software on custom technology platform
    4. Replacement

27. The alternatives were assessed against Enbridge's IT Infrastructure criteria, as previously defined:
    a. Reliability
    b. Security
    c. Availability
    d. Supportability
    e. Maintainability

28. The following describes each option assessed. At the end of the section a summary table shows a comparison of the options when assessed against the IT Technology criteria.

Alternative Option 1: Do Nothing

29. As previously mentioned, the underlying Microsoft platform for this system will not be supported after 2015 (Windows Server 2003). This will result in system instability and unacceptable risk to external threats. The challenges with supporting the aging application and infrastructure will get worse over time. This will significantly increase technology and vendor risk which magnifies support issues. Enbridge has concluded that this level of risk is unacceptable. Having an enterprise system that is not supported exposes the utility to an unacceptable lack of security to online attacks and other threats to the enterprise network. Enbridge currently receives on average 1 million attacks per month. This foundational system is interfaced to many other key systems (e.g. CIS, Oracle, etc.), providing additional risk since having one system compromised, also compromises the other systems that interface. Having a non-supported system also means that the system will no longer receive the regular maintenance updates from the supporting vendor leading to operational risks. Failure of these systems could force movement to manual processes and in many cases could prevent critical utility functions (e.g. customer billing). Current staffing levels and protocols at the utility are not aligned to operate on this type of manual basis for more than a very short period of time. This scenario could result in focusing on emergency only functions and delaying other non-emergency related work. Therefore, the Do Nothing option was not deemed prudent.

Alternative Option 2: Upgrade Current Software to Most Recent Supported Version

30. The vendor's (CGI/Logica) current product is an EAM product ("ARMS") that was created from a different platform than STORMS. There is no standard upgrade path to the vendor's current product, ARMS, so it was not considered as an upgrade

option. ARMS is included as a replacement option and will be assessed among the other EAM products available in the market as part of the competitive bid process.

31. There is a more recent version of STORMS than what Enbridge currently has, which is STORMS ver. 3.7. This is not a product that the vendor currently sells in the marketplace. This product is also not compatible with operating systems later than Windows Server 2003 and will longer supported after 2015. Therefore, this option is equivalent to Option 1 - Do Nothing option above. There will also be the need to upgrade PMTS and iScheduler since the Existing Technology is not an integrated suite. The upgrade requires a significant effort in testing and migration of the changes that were implemented which are not available in the current version. Therefore, this alternative was not deemed prudent.

Alternative Option 3: Reconstruct Current Software

32. Enbridge has also considered a custom reconstruction of the current software. This would be a short term option that would enable these products to work on Windows Server 2008. Enbridge is not aware of any utility in North America that has taken a vendor’s older product and asked them to make it a custom application. This option would be a short term option since it would not have an upgrade path for the future. It would also require Enbridge to incur costs and risks associated with the vendor having a product that does not align with the rest of their product suite.

    a) Furthermore, the reconstruction does not address Existing Technology obsolescence related to the Storms / iScheduler application that will need to be rebuilt to operate on the latest version of the database and operating system. The version of the software would be custom for Enbridge, therefore further upgrades will become more difficult and costly. The version will only be certified to the current supported database version and operating system, requiring continuous custom rebuilds to address the technological obsolescence problem again with the product support cycle.

b) Additionally, there is no archive function in the application for the Existing Technology. The archive functions are a form of system maintenance where the size of the database is optimized on a regular basis. Without this function the unsupported database growth will not be sustainable.

c) Other deficiencies include the foundation of STORMS which is developed using a product called PowerBuilder. This was a technology used in earlier applications but have since been replaced with modern development standards that are more supportable and maintainable. The version of PowerBuilder currently used in the Existing Technology is also no longer supported and at end of life. Skill sets in the market related to these older technologies are not readily available and pose a problem to address issues as they occur.

d) For all of these reasons, the Reconstruct Current Software option was not deemed prudent.

<u>Preferred Option: Replacement Option (WAMS)</u>

33. The WAMS option includes selecting an EAM system for implementation to replace the Existing Technology. There are several EAM products in the current market and Enbridge will be moving forward with a competitive bid process culminating in the fall of 2013. This option will provide a more integrated system that is supported

and can follow a planned upgrade path. Given the complexity of the replacement it is prudent to examine other leading EAM solutions that will address both the technology issues and the evolving business needs. This option is the only one that sustains at an acceptable level the Reliability, Security, Availability, Maintainability and Supportability of business systems and applications that are critical to the operations of Enbridge. Enbridge intends to include the vendor's current EAM product, ARMS, in the evaluation of products. Therefore, replacement with the vendor's current product is considered a choice under this option, but only based upon the comparison to other viable bids. The Replacement option was deemed the only prudent option and was selected by Enbridge.

34. Figure 2 shows each option and whether they met or failed when compared against Enbridge's IT Infrastructure criteria.

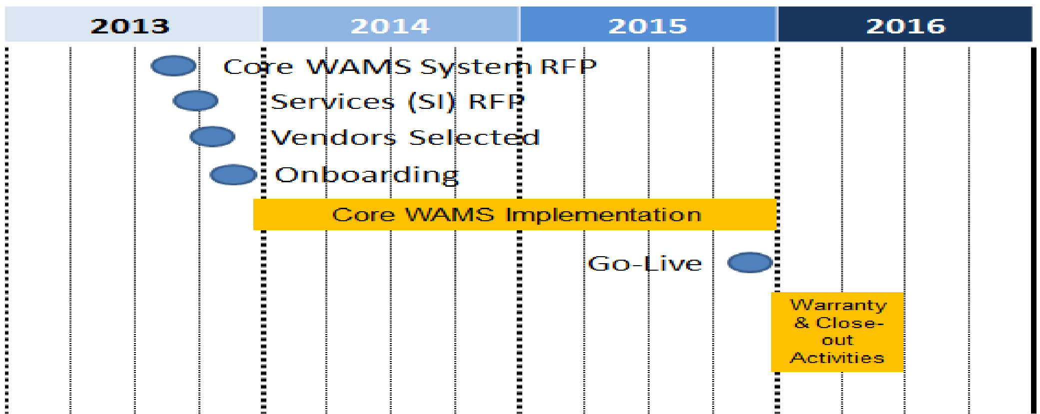
Figure 2: Option Comparison Against IT Infrastructure Criteria

	Criteria				
	Reliability	Security	Availability	Supportability	Maintainability
Option 1: Do Nothing	✗	✗	✗	✗	✗
Option 2: Upgrade to Vendor Supported Version	✗	✗	✗	✓	✗
Option 3: Reconstruct on New Platform	✗	✓	✗	✓	✗
Option 4: Replacement	✓	✓	✓	✓	✓

35. As indicated in Figure 3, Enbridge is evaluating business and system requirements in preparation for evaluation and procurement in the fall of 2013. The Company is

planning for a Go Live date in December 2015. Activities in 2016 relate to the warranty, stabilization period and program close-out activities.

Figure 3: WAMS Program High-Level Timeline



Required Capital

36. Initiatives like the WAMS Program are infrequent. As a result, this represents a significant increase to Information Technology ("IT") spending compared to typical years. Forecasted costs during 2014, 2015 and 2016 related to the WAMS Program are outlined in Exhibit B2, Tab 6, Schedule 2 (page 1) and replicated in Table 1 below. Activities in 2013 are largely preparatory for the WAMS Program and costs are lower than the other years. The capital cost in 2014 is greater than 2013 due to the need for the majority of technology purchases and detailed design to be done in that year. In 2015, spending is allocated to the configuration, testing and deployment. Activities in 2016 relate to the warranty, stabilization period and program close-out activities. Based on forecasted activities, $59.9 million will close to rate base in 2015 and $7.7 million in 2016.

Table 2: Capital Requirements ($000)

	Budget	Forecast		
DESCRIPTION	2013	2014	2015	2016
WAMS Program	500	35,700	23,700	7,700
TOTAL	500	35,700	23,700	7,700

37. The process for procuring the new system will be a competitive bid process, so details that have the potential to prejudice the bid process have not been included in this evidence. The major components included in this estimate are the following:
    - Hardware
    - EAM License
    - Other required Software / interfaces
    - System Integrator (SI)
    - Internal Cost (technical)
    - Internal Cost (business)
    - Training / Rollout
    - Warranty
    - Data Management / Migration

38. The process for procuring the new system and associated services will employ a competitive bid process. For this reason, details that have the potential to prejudice the bid process have not been included in this evidence. The proposed budget for the WAMS Program is based on best available information and several inputs were used including diligent inquiries with utilities in North America on similar initiatives, system vendors, system integrators and industry experts. Sync Energy has been retained to provide an independent expert review of the WAMS Program. Sync Energy brings more than 23 years of experience in the electric and gas utility industry, including EAM related projects. Please refer to Exhibit B2, Tab 6, Schedule 2 Attachment for the Sync Energy Report outlining the third party review

of the WAMS Program and the reasonableness of the proposed budget, schedule and approach. The Company is confident in the cost estimate based on best available information, and a few milestones will assist in reconfirming this budget. One such milestone is the system vendor / system integrator RFP that is scheduled to be completed in fall 2013. This milestone will occur after the Company has filed its evidence with the Board. The Company intends to update any relevant information to the Board once it is available.

39. A program of this magnitude takes significant time to plan and execute effectively. A diagram showing the timeline is included in the WAMS Program Description section above. In order to meet the 2015 “Go Live” date, significant activities need to occur in advance of that date. The schedule developed and proposed by the Company aligns well with other similar implementations in the industry.

40. All WAMS Program related costs supporting successful implementation of the EAM solution are included in the IT Capital capital budget. This includes all elements related to the WAMS Program as described above.

41. The Company is proposing to implement the EAM solution in December of 2015, with warranty extending into 2016. Similar to Enbridge’s SAP Customer Information System the technology asset will be depreciated over 10 years. Enbridge is proposing to apply Capital Cost Allowance (CCA) in the first 2 years, as allowed by Canada Revenue Agency, thereby minimizing the impact on rates for 2015 and 2016. Enbridge will continue to apply the Board approved treatment to costs in the interim related to the services for the Existing Technology.

Sync Energy

WAMS Program Review Report

For

ENBRIDGE

June 14, 2013

Acknowledgement
June 14, 2013

Mr. Will Akkermans
Sr. Director, System Operations
Enbridge Gas Distribution

Subject: Enterprise Work and Asset Management Project Review Report

Dear Mr. Akkermans,

Sync Energy is pleased to provide the enclosed report for the review of the Work and Asset Management Solution (WAMS) Program. Please feel free to contact me if you would like to discuss this report in more detail.

Sincerely,

Daniel C. Heineman (Chris)
President, Sync Energy, Inc.
Phone: 630-466-8651
Email: cheineman@syncenergy.com

WAMS Program Review Background

Enbridge Gas Distribution contacted Sync Energy to request an independent 3rd party review of their Work and Asset Management Solution (WAMS) Program. More specifically, Sync Energy was asked to consider Enbridge's WAMS Program and to provide a written opinion, based upon Sync Energy's involvement with projects of this nature in the utility industry, as to whether the WAMS Program both in terms of the approach and cost are consistent with current industry practice and experience. The elements of the review conducted by Sync Energy included:

- Program scope
- Program budget
- Program approach and methodology
- Industry trends related to EAM solutions in the utility industry
- Technology options considered by Enbridge

For the purposes of the review, Chris Heineman of Sync Energy met with representatives from Enbridge's Business and Information Technology (IT) group and the key member of the WAMS Program team to review key project documents, discuss planning activities to date and consider current Program cost estimates. This information was then considered against the numerous initiatives that we have been involved with of a similar nature to determine the reasonableness of Enbridge's approach and cost estimates relative to the experience of other utilities. A summary of the qualifications and experience of Mr. Heineman is attached.

Feedback on specific aspects of the WAMS Program

The next section of this document provides additional feedback on specific aspects of the proposed WAMS Program.

1. Enterprise Asset Management (EAM) in the Utility Industry

Over the past 25 years, the utility industry in North America has been slowly transitioning from custom development and best-of-breed "point" technology solutions to "enterprise" commercial-off-the-shelf (COTS) software products. Enterprise Asset Management (EAM) is an example of this trend in the industry. It was not uncommon for a utility company in the 1990s to have a different work management solution for each type of work (e.g. meter work, service work, construction work) and separate asset management systems and databases for each type of asset (e.g. regulators, valves, mains, etc.) The cost of supporting these systems and developing integrations with other corporate systems quickly became prohibitive and utilities started migrating toward consolidated software solutions that support many types of work and many types of assets all in a single system. This "enterprise" approach to work and asset management provides:

- A single system to support and maintain
- Lower software upgrade costs
- Significantly fewer interfaces to build and maintain
- Improved business performance management and reporting

Since 2005, Sync Energy has been involved in 14 different Work and Asset Management projects for utility companies and 100% of these projects included a consolidated system that combines all types of work and all types of assets in a single enterprise software solution.

2. Hosting and Outsourcing of Support for EAM solutions

Another EAM trend in the Utility industry that did not take off as predicted was the outsourcing or hosting of EAM solutions. In a hosted model, a 3rd party company owns the hardware and software and then provides the system as a "service" back to utility companies. While this approach is still used today, it is more common for utility companies to own and manage their own EAM solution in-house. In some cases, systems that were outsourced previously are being "re-insourced" to lower costs, increase flexibility, increase influence over software product direction, and provide a better service to business users. Duke Energy is an example of a company who recently ended an EAM application hosting arrangement and now provides that service in-house for reasons similar to those stated above.

Application support contracts involving 3rd party companies are still the most common way to provide application support, maintenance, and enhancements to EAM systems. Using this model, a 3rd party company such as a systems integrator or specialty IT company provides a small dedicated team for support and enhancement work. This is particularly common within the first few years of deploying a new solution when the support activity and enhancement requests are the highest.

3. WAMS Program Budget and Schedule

After reviewing the Enbridge WAMS Program budget, Sync Energy believes the estimated cost of the program is reasonable based on Sync Energy's knowledge of similar recent projects in the utility industry. There are many factors that drive the cost of implementing WAMS solutions for utilities including:

- Number of business processes and business organizations impacted
- Number of interfaces to other corporate systems
- Amount and quality of data to be migrated to the new solution
- Number of end-users to prepare and train for the new solution
- Size of service territory
- The number of other projects running concurrently
- The experience of the selected Systems Integration partner
- The number of systems to be replaced or decommissioned
- The EAM software product(s) selected

For Enbridge, a budget of approximately $67.6M to cover business labor, IT labor, Systems Integrator labor, travel expenses, hardware, software, and warranty work is very much in line with what other companies have spent on similar projects. While no two projects are exactly alike, a range of costs from $50M to $75M for this scope of work should be considered reasonable based on Sync Energy's experience with other projects.

The typical schedule for a project of this size and complexity ranges from 14 to 30 months once a software product has been selected and detailed process design work begins. The Enbridge plan to deploy a solution within 24 months is neither slow nor "aggressive" and should provide sufficient time for designing, testing, training and deployment. Sync Energy recommends that Enbridge look for ways to avoid a "big bang" deployment and consider options for rolling out the new solution in smaller "chunks" by work type, geography, etc. where practical to reduce deployment risk. Deployment options and alternatives are typically determined after software products and systems integrators are selected.

4. WAMS Project Approach

The approach that the WAMS Program is following to implement a new Work and Asset Management solution is very much in line with similar successful programs at other utility companies. Enbridge is following a typical Systems Development Lifecycle (SDLC) “waterfall” approach that begins with process analysis and requirements and then moves to software selection, design, build, test, and deployment phases. This is by far the most common approach used in the industry today for projects of this size.

The keys to success for this type of project include:

- Strong management support and leadership
- A small and empowered “core” team that represents the impacted business areas
- A comprehensive change management strategy and approach
- A disciplined program management office (PMO) and project methodology
- Realistic scope, schedules, and budgets.
- Gathering feedback and lessons learned from other utilities, conferences, and industry experts.

The Enbridge WAMS Program team appears to be addressing each of these key items as well as identifying and mitigating other project risks.

As the team moves ahead, it will be important to select an experienced systems integration partner that also brings a knowledgeable team and lessons learned.

5. Alternatives Considered for Existing Technology at Enbridge

Enbridge has identified 4 technical alternatives to address their aging systems. These options include:

1. Do nothing
2. Upgrade current software to most recent supported version
3. Reconstruct current software on a new technology platform
4. Replacement

While the first three options are the least expensive in the short term, these options only postpone the eventual replacement costs and delay business functionality of a new, modern EAM solution. Additionally, the first two options do nothing to address the business and security risks identified by Enbridge.

In particular, options 2 and 3 involve investing a significant amount of money and time into STORMS which is a product that was discontinued more than 6 years ago and has no supported path forward. The ability to find qualified STORMS technical development resources will also be a risk to these options. As far as Sync Energy is aware, neither of these two options have been attempted in the past 6 years by any other utility company. Additionally, any money spent upgrading, enhancing, or modifying the current software to extend the life should be considered “throw away” costs and will not provide any new business benefits to Enbridge such as new features or functions to improve business efficiency.

While many utility companies in North America have been faced with similar problems of aging and obsolete technologies, by far, the most common approach is to replace these systems with modern vendor supported EAM solutions. Sync Energy is aware of at least 4 companies in the past 6 years that have replaced or are currently replacing STORMS with a new EAM product. Examples include DTE Energy, National Grid, Duke Energy, and Tucson Electric Power.

Conclusions

The Enbridge WAMS Program is making steady progress toward the goal of implementing an enterprise work and asset management solution. The planning work performed by the WAMS team to date appears to be comprehensive and has leveraged lessons learned from other utilities and industry experts.

The WAMS Program approach, budget, and schedule at this stage of the project are reasonable based on Sync Energy's experience with similar projects in the industry.

About Sync Energy

Sync Energy was founded in 2005 and specializes in the implementation of Work and Asset Management solutions for the electric and gas utility industry. Sync Energy provides services ranging from business strategy, IT strategy, and architecture design to large-scale technology implementations for many of the world's largest utilities. Current and recent Sync Energy clients include:

- Duke Energy
- DTE Energy
- CenterPoint Energy
- Salt River Project
- Baltimore Gas and Electric
- Portland General Electric
- Southern California Edison
- Constellation Energy
- Tennessee Valley Authority
- Entergy
- Integrys Energy
- ONEOK
- Luminant
- Bord Gáis Energy

Mr. Heineman has over 24 years of experience in the areas of Transmission and Distribution Work and Asset Management solutions for Utilities. Project experience in these areas includes business strategy development, process improvement, application architecture design, large-scale program and project management, and Enterprise Application Integration.

Mr. Heineman has worked with over 30 different utility companies in North America, Europe, Asia, and Africa during his career.

Chris Heineman - CV

SUMMARY

Mr. Heineman has over 24 years of experience in Electric and Gas Utility Industry providing services ranging from business strategy, IT strategy, and architecture design to large-scale technology implementations for many of the world's largest utilities.

Areas of experience include Distribution, Transmission, and Generation enterprise solutions such as Work Management Systems (WMS), Enterprise Asset Management (EAM), Supply Chain Systems (SC), Geographic Information Systems (GIS), Outage Management Systems (OMS), Design Engineering, Engineering Analysis, and Customer Information Systems (CIS). Project experience in these areas includes business strategy development, process improvement, application architecture, large-scale program and project management, and Enterprise Application Integration (EAI).

Mr. Heineman is a member the International Electrotechnical Commission (IEC) and the American National Standards Institute (ANSI) and is leading a global effort to standardize integration between major Utility Industry applications. Mr. Heineman is the leader of Working Group 14 - Part 6 which defines the standard integration for Maintenance and Construction Work Management for T&D Utilities. Mr. Heineman is a frequent presenter of papers and training sessions at several Utility Industry conferences such as DistribuTECH, GITA, Pulse, and the Energy IT Expo.

President – Sync Energy, Inc. (2005 to Present)

Mr. Heineman is currently President of Sync Energy, Inc. specializing in providing IT and Business Consulting services to Energy and Utility companies.

Vice President - SAIC (2003 to 2005)

Mr. Heineman was a Vice President in SAIC's Global Systems Integration group specializing in Utility Industry business and IT solutions. Mr. Heineman was responsible for utility industry solutions based on technology from companies such as MRO/Maximo Software, Indus/Ventyx, Smallworld, ESRI, and other enterprise solutions.

Partner - Deloitte Consulting (2001 to 2003)

Mr. Heineman led and managed Deloitte Consulting's North American Energy Delivery practice within the firm's Utilities Industry. Mr. Heineman was responsible for relationships with leading Energy Delivery product vendors including MRO/Maximo, Indus/Ventyx, and WorkSuite/Logica. Mr. Heineman was also responsible for all mobile technology initiatives within the Utility practice and led engagements with several industry-leading mobile data solution providers.

Associate Partner - Accenture (1989 to 2001)

Mr. Heineman was part of Accenture's Global Energy Delivery practice. Mr. Heineman's responsibilities included the delivery of enterprise solutions to utility companies in North America, Europe, and Asia. Mr. Heineman also served as the key point of contact for several leading industry solution providers including Indus International and WorkSuite.

CONSULTING EXPERIENCE

Salt River Project – SAP ERP Implementation Project; 18 months: Served as solution architect and end-to-end process lead supporting Salt River Project (SRP) with the implementation of SAP for Finance, Supply Chain and Human Resources. Key focus areas include integration with all work and asset management solutions for electric T&D, power generation, water, facilities, and fleet management. Responsible for developing to-be end-to-end processes and end-to-end test scenarios for all major work and asset management enterprise processes. Scope included system and process impacts in all legacy areas such as EAM, GIS, graphic design, mobile data, CIS, outage management, resource scheduling, etc.

CenterPoint Energy – Enterprise Asset and Work Management Strategy Project; 3 months: Supported CenterPoint Energy in the development of an EAM strategic roadmap. Scope included SAP PM and Maximo EAM products, Ventyx Mobile and Scheduling, ESRI GIS, and various asset condition monitoring solutions.

Portland General Electric – Enterprise Work and Asset Management Project; 9 months: Supported PGE's assessment, design, and build phases for the implementation of an Enterprise Asset Management solution based on IBM's Maximo product. Project scope included power generation, electric transmission and distribution and IT Asset Management. Major points of integration include PeopleSoft for Financials, Supply Chain, and HR, ESRI GIS, and legacy customer billing systems.

Hydro Quebec – EAM Systems Optimization Project; 4 months: Supported Hydro Quebec and IBM with development of a proposed solution architecture for enterprise work and asset management. Scope included power generation, transmission and distribution, fleet, and facilities. Legacy EAM systems included SAP PM and Maximo EAM.

Sempra Energy – Construction Work and Asset Management Project; 6 months: Supported Sempra's distribution construction Work and Asset Management project during the requirements phase of the project. The primary responsibilities include assistance with function requirements, scope, and implementation approach. Mr. Heineman is also responsible for the development of a comprehensive Request for Proposal (RFP) for systems integration services. The project scope included all distribution construction work for Sempra's Gas and Electric business units. Sempra Energy is the largest supplier of natural gas in North America with over 8 million gas and 1 million electric customers. Software products being implemented include; SAP for work and asset management; Telvent (Miner and Miner) Designer for graphical work design, and ClickSoftware for scheduling, dispatch, and mobile data.

Bord Gais – Enterprise Work and Asset Management Project; 12 months: Performed the role of "Solution Architect" on Bord Gais' Work and Asset Management project. Mr. Heineman was responsible for all functional aspects of the project including, requirements gathering, process design, software knowledge, integration approach, and T&D industry best practices. The project scope included all types of work from large gas transmission projects and maintenance to small distribution construction and customer service work, Bord Gais is the largest supplier of natural gas in Ireland with over 700,000 residential, commercial and industrial customers. Software products implemented include; Maximo EAM for work management, asset management and supply chain; ClickSoftware for scheduling and dispatch, and Syclo for mobile data. Major points of integration include Oracle financials, Smallworld GIS, MS Project, and legacy Customer systems.

Duke Energy – Enterprise Asset Management and Supply Chain Project; 26 months: Performed the role of "Business Architect" on Duke's Enterprise Asset Management (EAM) project. Responsible for managing issues and functional design across Fossil Generation, Electric T&D, Gas Operations, Fleet, and Supply Chain. Duke implemented Maximo 6.x as an enterprise EAM and Supply Chain solution across their Carolinas and Midwest service territory. Major points of integration include PeopleSoft Financials and HR, Smallworld GIS, Syclo, Bentley (Cook-Hurlbert) Expert Designer, PLS CADD, AutoDesk, and Primavera.

Nevada Power / Sierra Pacific Power – Work and Asset Management Project; 2 Months: Led an effort to develop the business case for implementing enterprise Work and Asset Management across the NP and SPP gas and electric service territories in Las Vegas and Reno, Nevada.

Providing assistance in identifying qualified vendors and service providers, developed and RFP and evaluation criteria, and provided general guidance in the overall project direction. Also performed the role of “external auditor” and reporting project progress to Senior Management steering team over a multi-year period.

SRP (Salt River Project) – Asset Management Project; 28 months: Supported SRP as a T&D Industry “Best Practice” advisor and Maximo product expert related to the implementation of a new Work and Asset management system for SRP’s Electric Transmission and Distribution business. The Asset Management Project (AMP) includes the implementation of leading industry packages such as IBM’s Maximo, Indus’ Service Suite, and Digital Inspections’ Cascade. Major integration points include Smallworld GIS and Legacy financial and materials management systems.

DTE (Detroit Edison) – DTE2 Work and Asset Management project; 20 months Acted as project advisor to DTE as part of a multi-year Work and Asset Management and ERP Implementation project. DTE selected SAP for enterprise Finance, Accounting, HR, and Supply Chain, MRO Software for Enterprise Work and Asset Management, and ESRI for enterprise GIS. The project scope included DTE’s Fossil Generation, Nuclear Generation, and Gas/Electric T&D Businesses.

Entergy – Distribution Work and Asset Management project; 3 Months: Engagement lead to develop a business case and implementation plan to replace Entergy’s Gas and Electric Distribution Work Management systems, Mobile Data systems, and Graphical Design systems. Project team developed a detailed business case, identified qualified vendors and products, created a detailed cost estimate and implementation plan, and developed and evaluated a vendor RFI.

Entergy – Nuclear IT Strategy and Work Management / Supply Chain Standardization; 6 Months: Engagement Lead to develop an overall 5 year IT Strategy for 10 Nuclear Power Plants across 7 US states. A team led by Mr. Heineman reviewed nearly 1200 applications currently used by the nuclear fleet and developed a prioritized set of 43 business driven IT initiatives to consolidate and standardized the fleet. In the area of Work Management and Supply Chan the team reviewed current solutions from MRO Software, Indus (Passport and EMPAC) and SAP and recommended an approach for fleet standardization. Mr. Heineman is currently leading the implementation planning effort the new solution across the fleet.

PacifiCorp – Enterprise Work and Asset Management and GIS Strategy; 4 Months: Led Engagement to develop a strategic Asset and Work Management Strategy for PacifiCorp’s Power Delivery business. Developed a multi-year GIS deployment strategy including project requirements, priorities, phasing, budgets, and implementation plans. Evaluated PacifiCorp’s current organization, processes, and technology and recommended a series of improvements.

PacifiCorp – Business Technology Framework; 3 Months: Led a project to help PacifiCorp collect, analyze, and prioritize all IT funding requests across the Power Delivery business. Developed an automated method to measure strategic value, business value, disruption, and risk of more than 80 current and future IT initiatives.

Siemens Power Generation – IT Strategy and Application Rationalization; 4 months: Led a project to review 1000+ current IT applications and 75+ in flight IT projects. The project team developed at To-Be application architecture and developed a model to prioritized all in flight and future IT projects.

Hydro One – Mobile Asset Information System; 6 Months: Lead Engagement Partner on a project to deploy over 300 Windows CE and Windows 2000 based mobile devices to Hydro One’s Field Services organization. Using software from Telispark, the project team configured applications to collect Asset, Inspection, and Work Order information from hand held and laptop devices. The data collected was integrated to Hydro One’s Indus Passport Work and Asset Management System. Team responsibilities included the verification of mobile data requirements, process definition and design, mobile application configuration, integration with multiple back-end systems, testing, and deployment of the new system and processes.

Southern California Edison – Enterprise Application Architecture; 6 months: Led a team responsible for the development of SCE's "To-Be" enterprise application architecture as part of an overall IT cost reduction effort. The scope of the project included all aspects of SCE's business including Energy Trading, Energy Generation, Energy Delivery, Customer Service, and Back Office Support Services. Deliverables included To-Be Application Maps, High Level Process Flows, Information Exchange models, Candidate Product Identification, and a Prioritized Migration plan. The end result of the project included recommendations to reduce SCE's current application portfolio from over 800 to approximately 100 over a 5 year period.

NSTAR – Operating Model Improvement Project; 8 Months: Lead Partner on the requirements, design, and implementation of the "Operating Model Improvement" project for a large New England based electric and gas distribution company. Led a team that used Enterprise Application Integration (EAI) middleware and IEC WG14 industry standard messaging architecture to integrate operational systems including; M3i Outage Management, Passport Work and Asset Management, ESRI GIS, SNC Lavalin SCADA, CYME Engineering Analysis, and a custom CIS system.

Wisconsin Electric / Wisconsin Gas – Work Management Implementation; 9 Months: Led a team responsible for developing an operational strategy and business case for an enterprise Work Management System (WMS). Developed "as-is" and "to-be" business processes as well as business requirements and criteria for software selection. Responsible for overall project management including functional areas, change management, and technology.

Southern California Edison – Transmission Maintenance and Inspection Project; 4 Months: Led a team of SCE business and technology representatives responsible for migrating the Transmission Maintenance and Inspection processes to the new Enterprise Work Management System based on Indus Passport. Responsibilities included scope definition, management of manual data conversion process and tools, requirements definition for Mobile Data technology, and overall project management.

Southern California Edison – T&D Business Architecture Project; 4 Months: Led a team of SCE business, technology, and contract representatives responsible for developing an "as-is" and "to-be" business architecture for the Transmission and Distribution Business Unit (TDBU) Responsibilities included confirmation of operating strategy with TDBU business executives, development of "to-be" application, data, and technology architectures, and presenting results to SCE management team.

Southern California Edison – Wires Integration Project 8 Months: Worked with SCE business team leaders to resolve critical business issues related to the implementation of an enterprise Asset and Work Management System based on Indus Passport. Deliverables included resolutions to the "Top 10" business issues, a strategy for the use of field automation tools, an approach for developing "unit cost" tracking of TDBU work, and software selection for work scheduling. SCE converted 4.2 million distribution and substation assets into Indus Passport and established over 2 million Preventative Maintenance triggers (PMs)

Nicor Gas – IT Strategy Project 3 Months: Worked with Nicor executives to identify and prioritize IT projects and develop a five year IT Plan. The project involved reviewing all of Nicor's existing systems and processes and identifying opportunities for improvement, consolidation, or package replacement. Worked closely with Nicor's CIO and VPs of Distribution Maintenance and Operations.

Nicor Gas – Customer One Project 8 Months: Led a team responsible for implementing a packaged Customer Information System (CIS) based on Accenture's Customer/1 CIS product. Responsibilities included managing three teams in stage 1 of the project; the Functional Fit Assessment team, the Conversion team, and the Interface team. Worked with Nicor client executives to determine scope and estimate the total cost of the project. Also provided teams with the guidance and tools to complete their work such as best practice methodologies and documentation repository tools.

Commonwealth Edison – Geographic Information System (GIS) Project 12 Months: Served as the project manager for the implementation of an Automated Mapping and Facilities Management system (AM/FM). The new system replaced ComEd's 56,000 paper maps with electronic versions using the Smallworld GIS products. The new system also supports other functions such as Engineering Design, AutoCAD Import/Export, and interfaces with several other corporate systems at ComEd.

Baltimore Gas and Electric – Industrial Billing System Project 12 Months: Served as the project manager and team leader for the implementation of a custom Client Server Industrial Billing system for BG&E. The new Industrial Billing system produces bills in Microsoft Excel and is integrated with BG&E's corporate DB2 database. Responsible for implementing the first 2 phases of a three phase project including requirements and design, build, and integration test.

Hong Kong Electric – Work Management System Project 1 Month: Performed a four week review of a detailed design for a new Work Management system at Hong Kong Electric. The system design included the installation and customization of an enterprise Work Management System and the integration of Intergraph's FRAME AM/FM system

Southern California Gas Company – Work Management System Project 8 Months: Served as a functional/technical analyst and design team leader for the implementation of a packaged Work Management System at the Southern California Gas Company. Responsible for design, build, and system test and training all other project design analysts in the areas of the WMS system functionality and Client/Server technical design

Connecticut Natural Gas Company – Work Management System Project 14 Months: Served as a functional team leader for the implementation of a packaged Work Management software package at Connecticut Natural Gas Company in Hartford Connecticut. At CNG, Mr. Heineman was responsible for the Compatible Units, Work Planning, Work Scheduling/Dispatch, Field Reporting and Closing subsystems in Work/1. Mr. Heineman organized and completed the detailed design phase for these areas. Mr. Heineman was also responsible for the System Test Preparation, System Test Execution, and User Acceptance Test of the entire Work/1 system. Mr. Heineman also assisted in the development of User training materials.

BC Gas – Work Management System Project 12 Months: Served as a functional team leader for the implementation of a custom client-server Work Management software package at BC Gas in Vancouver British Colombia. At BC Gas, Mr. Heineman was responsible for the functional design of several system components including; Work Planning, Work Closing, and Compatible Units.

Baltimore Gas and Electric – Customer Information Project; 6 months: Served as technical analyst responsible for the integration test, business process test, and conversion of the enterprise residential billing system for BG&E.

Texas Utilities – Nuclear Power Plant Maintenance Project; 8 months: Served as a technical analyst responsible for designing, coding, and testing several applications related to routine maintenance and inspections for a two unit nuclear power plant in Texas.

OTHER EXPERIENCE

IEC TC57 WG14 – Leading member of the International Electrotechnical Commission, Technical Committee 57, Working Group 14 standards organization. The goal of Working Group 14 is to develop a set of industry standard processes and EAI based inter-application messages for electric utilities. Currently leading the standards development in the area of Construction, Maintenance, and Mobile Data Technologies.

SYSTEM EXPERIENCE

Software / Products: IBM Maximo, Indus/Ventyx Passport, SAP, Indus EMPAC, Severn Trent STORMS, Logica ARM Suite, Accenture's Work/1 and Customer/1, M3i, CES, Intergraph, Smallworld, ESRI, AutoCAD, MapFrame, Bentley Expert Designer, MDSI, ClickSoftware, Syclo, Telispark, Primavera, MS Project.

Development Tools / Languages: COBOL, C++, VisualBasic and VBA, SQL

Hardware / Operating Systems: Windows 95/97/NT/2000/XP/Vista/Windows 7

Middleware / Databases: Vitria, WebMethods, Tibco, SeeBeyond, DB2, Oracle, Microsoft Access

General Tools: Microsoft Office Professional

EDUCATION

Advanced Business Management
Northwestern University, Kellogg Graduate School of Management

Bachelor of Science, Systems Engineering
University of Virginia

PROFESSIONAL AFFILIATIONS

International Electrotechnical Commission (IEC) TC57 - Working Group 14

American National Standards Institute (ANSI)

TRAINING

Systems Integration, Business Analysis, Business Process Re-engineering, Project Management, Technical Architecture, Methodology, Creating Client Value, Architecting Business Change

PRESENTATIONS

Various Utility Industry EAM presentation including:

DistribuTECH 1997 - Integrated Utility Operations Environment

DistribuTECH 1999 - Integration BUS - One Year Later

North America Utility Leadership 2001 – California Utility Deregulation

DistribuTECH 2002 - Developing Strategies For Establishing A Successful Enterprise Application Integration (EAI) Infrastructure

Pulse 2011 – Bord Gáis Networks (Ireland Gas) – Transformation Program

CAPITAL BUSINESS AREA: FACILITIES AND GENERAL PLANT (2014 – 2016)

1. The purpose of this evidence is to present the Facilities and General Plant capital expenditures budget for the 2014, 2015 and 2016 forecast period. Facilities and General Plant expenditures relate to Facilities Services and Fleet & Equipment. This exhibit provides the Ontario Energy Board (the "Board") with a detailed breakdown and explanation of the various categories of capital expenditure spends and justification for planned major projects over $2 million.

Role of Facilities Services and Fleet & Equipment

2. The Facilities Services department manages all Enbridge Gas Distribution Inc. ("Enbridge", or the "Company") facilities (currently 20 properties, 11 owned and 9 leased, totaling 818,000 square feet) ensuring that appropriate facilities and workspace is available to support and respond to the operational requirements of the Company and provides 24/365 response to all building emergencies. The department is responsible for the planning and utilization of buildings to provide a safe and healthy work environment for all building occupants while optimizing the use of and efficiency of all facilities and ensuring adherence to building codes and by-laws, fire codes, and environmental regulations.

3. Facilities Services conducts strategic property planning, acquisition and disposal of properties, lease administration, asset management and internal project management of all reconfiguration, relocation, renovation and construction projects. The daily operation of buildings and grounds entails the maintenance and upgrade of building systems, energy management initiatives, premise security, life safety systems, business continuity planning, mail and delivery and housekeeping services.

Witnesses: D. Lapp
P. Rapini
R. Riccio

4. The Fleet & Equipment group has the overall responsibility for the administration, operation and maintenance of the utility fleet including cars and trucks, utility trucks and service vans. In addition, this group administers and maintains the heavy equipment employed such as backhoes, lifting equipment and welding machines. This group also maintains the smaller tools utilized by the Company including jackhammers and drills.

5. The Fleet & Equipment group manages the purchase and acquisition of all transportation equipment, including light duty and medium duty vehicles required for the safe and reliable operation of the utility. It also includes the purchase and acquisition of all heavy work equipment and small tools. Included with the capital associated with transportation equipment are the capital costs associated with converting and operating the fleet using compressed natural gas for fuel (NGV).

Capital Budget for Facilities and General Plant

6. Table 1 provides a summary of forecast capital expenditures by plant account for Facilities and General Plant for the 2013 to 2016 forecast period.

Table 1

	($000)	Col. 1	Col. 2	Col. 3	Col. 4
Item No.		Estimate 2013	Budget 2014	Budget 2015	Budget 2016
1.1	Structures and Improvements	6,865	8,000	8,100	6,500
1.2	Leasehold Improvements	558	4,920	3,120	270
1.3	Office Furniture and Equipment	1,932	4,630	4,680	4,380
1.4	Fleet & Equipment	6,310	6,064	6,129	6,143
1.	Total	15,665	23,614	22,029	17,293

7. Table 2 provides a detailed breakdown of Facilities and General Plant capital expenditures into categories of spend and major projects over $2 million for the 2014 to 2016 forecast period.

Table 2

	($000)	Col. 1	Col. 2	Col. 3	Col. 4
Item No.		Estimate 2013	Budget 2014	Budget 2015	Budget 2016
	Categories of Spend:				
1.1	New Workspace and Alterations	3,208	3,745	2,685	2,810
1.2	Building Improvements and Upgrades	4,215	5,625	3,435	3,960
1.3	Office Furniture and Equipment	1,932	4,630	4,680	4,380
1.4	Light & Medium Duty Transportation Equipment	3,260	3,080	3,080	3,080
1.5	Heavy Work Equipment	815	770	770	770
1.6	Small Tools & Equipment	1,618	1,575	1,575	1,575
1.7	NGV Equipment	617	639	703	719
1.	Sub-Total	9,355	14,000	10,800	11,150
	Projects over $2 million:				
2.	Relocation of the Meter Shop to a Leased Property	0	3,550	0	0
3.	Convert Vacated Space at VPC into Offices	0	0	2,100	0
4.	Relocation of Fleet Garage to a Leased Property	0	0	3,000	0
5.	Total	15,665	23,614	22,029	17.293

8. A description of the items addressed within each of the categories of spends identified are as follows:

   a. New Workspace and Alterations. This category includes capital expenditures required to build new offices, conference rooms and common areas as well as industrial workspace such as warehousing and operations yards at any of the existing owned and leased buildings as well as any new additional facilities that are acquired. The needs of the Company are changing constantly and it is critical that the facilities meet the demands in an effective and timely manner. While the workspace standards and designs are developed to allow maximum flexibility without constant staff workspace reconfigurations and relocations, it is necessary to adapt to meet the changing demands.

b. Building Improvements and Upgrades. This category includes capital expenditures required to maintain the existing portfolio of buildings and includes replacement of building components such as roofs, windows, doors, carpet and ceiling tiles, building system upgrades (HVAC, electrical, life safety systems, data center), site improvements (landscaping, parking lots, fencing, gates, equipment yards) and energy efficiency projects (lighting, automated building controls). The individual building components have a finite life from a functional, operating cost and risk perspective. Several examples include:
   - A roof or a chiller may have a useful life of 15 to 20 years depending on the maintenance performed over the years; however, failing to replace it at the end of its life cycle time will eventually result in equipment failure, high operating costs and occupant disruption.
   - Site improvements are essential in upgrading to meet current municipal and Enbridge safety standards.
   - Structural components of buildings such as exterior walls, staircases, do not age gracefully may require major restoration.

c. Office Furniture and Equipment. This category includes capital expenditures required to both replace existing furniture and equipment and furnish all new planned building space. This grouping includes system furniture, chairs, conference room and common space furniture, file cabinets and bookcases. Furniture replacement is required as the existing system furniture was implemented over 25 years ago and is at end of its life cycle.

The Company's existing REFF furniture systems were purchased in the mid-1980s when the concept of systems furniture was first implemented. The office environment has evolved immensely over the past thirty years.

- Warranty, obsolescence & fatigue: existing REFF furniture systems had a 10 year warranty which reflected anticipated use length. Today, that has increased to 15 or 20 years which is recognized by LEED and well beyond the expected lifecycle of the product. Enbridge systems furniture is approaching 30 years and if a replacement program is not initiated, fatigue and failure will become an issue.
- Ergonomic requirements are changing; supporting the Company's goal to zero injuries in the office, the height of the existing fixed workstation at 29" is a contributing factor of repetitive strain injury. Current standard workstations allow for adjustable height work surfaces - allowing the employee to adjust their primary work surface to the appropriate height or to stand - the current approach to ergonomics.
- A growing body of research links high quality indoor environments with access to natural light and views to gains in productivity, decreased absenteeism and improved employee morale. Providing for the

building occupants a connection between indoor spaces and the outdoors through the introduction of mid height workspace systems and perimeter placement. These strategies will improve the indoor environment of Enbridge facilities by exposing occupants to natural light.

- Workstation design to make use of materials and features reducing the "cubical feel". New systems are designed to allow for wiring of power and networks.
- Attraction and engagement is a concern of many organizations today. It's not just about attracting and retaining - it's about engaging employees while they are in their workplace. The Company's new systems furniture helps create an engaging and collaborative environment.

d. Light & Medium Duty Transportation Equipment. This category includes light duty vehicles, which are all vehicles under 4500 kg, including cars, pick-up trucks and vans, and medium duty vehicles, which are vehicles over 4500 kg, including utility trucks, flat-bed trucks, dump trucks and trailers.

e. Heavy Work Equipment. This category includes pieces of heavy work equipment including backhoes, welding machines, compressors and lifting devices such as hiabs and sidebooms.

f. Small Tools & Equipment. This category includes small tools and equipment, including jackhammers, drills, soil compactors, combustible gas indicators, generators, etc.

g. NGV Equipment. This category includes fleet vehicle NGV conversion kits and their installation as well as the associated NGV cylinders. Currently, about 75% of the Company's fleet vehicles are either dedicated natural gas or bi-fuel (natural gas and gasoline). Also included are the capital costs associated with the NGV compressor station facilities used for refueling the Company fleet at Enbridge facilities.

9. There is one major project within the Facilities and General Services capital expenditures for 2014 to 2016. That project relates to activities to remove non-office functions from the Company's Victoria Park Complex ("VPC") site to other locations, and then to use the vacated space for office functions. The costs related to this major project are set out at Items 2 to 4 of Table 2 above. This project is discussed within the project description document appended as "Attachment 1".

10. The following sections provide details about the forecast budgets for Facilities and General Plant for 2014 to 2016.

2014 Budget

11. The 2014 capital expenditure budget for Facilities and General Plant is $23.6 million. Set out below is a breakdown of the categories of spend and major projects for 2014:

    i. New Workspace and Alterations – $3.8 million. The general activities under this category are described above. The most significant projects planned for 2014 include:

- Thorold Data Center expansion (phase 2) - $350,000
- Thorold mezzanine conference center - $500,000
- Thorold parking lot expansion - $240,000
- Building addition to the Technical Operations Centre for Engineering Materials Evaluation Center - $1.25 million ($625,000 in 2014 and $625,000 in 2015)
- Leasehold improvements for a new operations facility replacing the Casselman operations depot - $500,000

The balance of the budget for this category of spend is required for workspace reconfigurations and relocations necessary to meet the changing demands in the various owned and leased facilities.

ii. Building Improvements and Upgrades – $5.6 million. The general activities under this category are described above. The most significant projects planned for 2014 include:

- VPC Head Office parking lot repaving and sidewalks and lighting - $560,000
- Brampton Colony Court Operations Depot renovations and upgrades - $750,000
- Scarborough Kennedy Road Operations Depot renovations and upgrades - $750,000
- Thorold office renovation - $300,000
- Ottawa Coventry Road Administrative building 1st floor office renovation - $350,000

The balance of the budget for this category of spend is required for upgrades to maintain the existing portfolio of buildings.

iii. Office Furniture and Equipment – $4.6 million. The general activities under this category are described above. For 2014, much of the budget is required to replace existing furniture that is well beyond its expected lifecycle for the planned office renovation projects at the both Brampton Colony Court and Scarborough Kennedy Road operations depots and both the Thorold and Ottawa Coventry Road administrative offices. This grouping includes system furniture, chairs, conference room and common space furniture, file cabinets and bookcases.

iv. Fleet & Equipment - $5.4 million. The Capital costs for these items relates to replacement of these assets, or additions to the asset pool. Replacement occurs when the assets come to the end of their serviceable life, or the required maintenance costs are not justified relative to replacement. The Company's budget assumes that Enbridge will maintain the same pool of fleet vehicles over the 2014 to 2016 period.

- Light & Medium Duty Transportation Equipment - $3.08 million. There are no forecast increases in the light & medium duty transportation equipment units through the forecast period. This number is expected stay at the 2013 levels of 815 units. The cost forecast is based on review of the list of vehicles likely to require replacement (based on age and repair history) and forecasting the replacement cost for such vehicles.
- Heavy Work Equipment - $0.77 million. There are no forecast increases in the heavy work equipment units through the forecast period. This number

is expected stay at the 2013 levels of 405 units. The cost forecast is based on review of the list of vehicles likely to require replacement (based on age and repair history) and forecasting the replacement cost for such vehicles.

- Small Tools & Equipment - $1.58 million. Due to the variety of items in this category and their associated unit costs, the number of tool and equipment units varies from year to year. The cost forecast is based on estimates of replacement requirements for tools and equipment, as well as allowance for new technologies and tools that may enhance safety and efficiency of operations (ie. keyhole technology) that become available over the 2014 to 2016 term.

iii. NGV Equipment - $0.64 million. The NGV costs primarily relate to three items:

a. Compressed Natural Gas (CNG) cylinders for Company fleet vehicles. These are the fuel storage cylinders onboard the vehicles. When a gasoline vehicle is converted to run on natural gas, a new cylinder is installed. There are mandated inspection and retesting / recertification requirements for these cylinders they have been installed. The associated cost is estimated from the number of cylinders due to expire in any given year multiplied by the historical cost to retest/recertify

b. Conversion of new fleet vehicles. There are two cost components associated with converting new vehicles purchased by the Company to NGV. The first is the cost to buy and install conversion kits for the new vehicles, while the second is the cost to buy and install fuel storage cylinders for these same vehicles.

c. CNG refueling stations. There are costs associated with capital improvements to allow ongoing operation of the refueling stations used to fuel Enbridge's fleet. This includes replacement or refurbishment of worn major components (dispenser nozzle replacements, dryers refurbishment, compressor rebuilds, etc).

iv. Planned major projects over $2 million in 2014 are as follows:

- <u>Relocation of the Meter Shop from VPC to a Leased Property</u> - $3.6 million. This project is required to relocate the meter shop operation from its current VPC head office location to a more appropriate location in a leased facility. Details for this project are discussed within the project description document at Exhibit B2, Tab 10, Schedule 1, Attachment 1.

<u>2015 Budget</u>

12. The 2015 capital expenditure budget for Facilities and General Plant is $22.0 million. Set out below is a breakdown of the categories of spend and major projects for 2015 :

i. New Workspace and Alterations - $2.7 million. Included in the 2015 budget is $625,000 for the completion of the building addition to the Technical Operations Centre for EMEC warehouse space expansion. This project is planned to start in 2014 for a total cost of $1.25 million over the two year period. The balance of the budget for this category of spend is required for workspace reconfigurations and relocations necessary to meet the changing demands in the various owned and leased facilities.

ii. Building Improvements and Upgrades – $3.4 million. There are two significant projects planned for 2015:

- Ottawa Coventry Road Administrative building 2nd and 3rd floor office renovation project - $350,000.
- Emergency Operations Centre (“EOC”) at the VPC Head Office - $1.2 million over the 2015 and 2016 forecast period ($500,000 in 2015 and $700,000 in 2016). As the Company has adopted the Incident Command System (“ICS”) model for emergency response, the need for a dedicated EOC was identified to improve the emergency response capacity within Enbridge Gas Distribution.

The balance of the budget for this category of spend is required for upgrades to maintain the existing portfolio of buildings.

iii. Office Furniture and Equipment – $4.7 million. In 2015, significant planned projects include replacement of existing furniture that is well beyond its expected lifecycle for the planned office renovation at the Ottawa Coventry Road administrative offices and approximately one half of the furniture required for the new office space planned for the VPC head office facility will be purchased.

iv. Fleet & Equipment - $5.4 million. The Fleet & Equipment budget is forecast to remain flat through the 2014 to 2016 period. The explanation of these costs is set out above. category are developed based on the depreciation of these assets, where replacement generally occurs, either once they have come to the end of their useful life, or the required maintenance costs are not justified relative to replacement.

v. NGV Equipment - $0.70 million. See above.

vi. Planned major projects over $2 million in 2015 are the following:

- Conversion of the vacated space at VPC into office space - $2.1 million. Once the meter shop relocation project is completed, the vacated space at the Victoria Park Complex will be transformed into office space to accommodate forecasted office space needs at the head office, thus avoiding significant lease costs and associated build out costs to occupy nearby office towers. Details for this project are discussed within the project description document at Exhibit B2, Tab 10, Schedule 1, Attachment 1.
- Relocation of the Fleet Garage to a Leased Property - $3 million. The fleet garage at the VPC head office services the entire GTA with a primary focus on Operations with heavy vehicles, construction equipment, pickup trucks and smaller support vehicles. There are several safety issues regarding the mixed use nature of the VPC head office facility with both industrial and office functions on the same site. The project plan is to secure a new building shell on a suitable site and to retire the current building. Details for this project are discussed within the project description document at Exhibit B2, Tab 10, Schedule 1, Attachment 1.

2016 Budget

13. The 2016 capital expenditure budget for Facilities and General Plant is $17.3 million. Set out below is a breakdown of the categories of spend and major projects for 2016 :

i. New Workspace and Alterations – $2.8 million. In 2016, the most significant project planned is $550,000 for the expansion of the parking lot at the VPC head office facility. The project plan is to demolish the 45 year old fleet garage and construct a new parking lot in its place to meet the parking space requirements at the VPC head office. The balance of the budget for this category of spend is required for workspace reconfigurations and relocations necessary to meet the changing demands in the various owned and leased facilities.

ii. Building Improvements and Upgrades – $4.0 million. There is one significant project planned for 2016:
   - A budget of $700,000 is for the completion of the Emergency Operations Centre ("EOC") at the VPC Head Office. This project is planned to start in 2015 for a total cost of $1.2 million over the two year period.

   The balance of the budget for this category of spend is required for upgrades to maintain the existing portfolio of buildings.

iii. Office Furniture and Equipment – $4.4 million. In 2016, replacement of existing furniture that is well beyond its expected lifecycle will continue and the balance of the new furniture required for the new office space planned for the VPC head office facility will be purchased.

iv. Fleet & Equipment - $5.4 million. The Fleet & Equipment budget is forecast to remain flat through the 2014 to 2016 period. The explanation of these costs is set out above. .

Witnesses: D. Lapp
P. Rapini
R. Riccio

v. NGV Equipment - $0.72 million. See above.

vi. There are no planned major projects over $2 million in 2016.

Productivity

14. There are productivity savings that are included within the Facilities and General Plant budget for the 2014 to 2016 forecast period. Examples of productivity savings include the following:

i. Enbridge has negotiated directly with its preferred furniture manufacturer, in order to obtain the maximum discount pricing available, and has locked in this pricing for five years;

ii. Enbridge has implemented a process through which high value construction materials (such as wall systems, flooring and HVAC) are directly procured by Facilities Services and supplied to the general contractor, thus avoiding significant mark-ups on construction projects;

iii. The plan to create additional office and parking space at VPC will be cost-effective. This will allow the Company to reduce the amount of high-cost office space being leased, as employees currently in leased space can move to the VPC site. By doing this, the Company can take advantage of the tenant common areas and support space that already exists at VPC, rather than paying for such amenities as part of the rent for the currently leased space. The cost of the leased space to house the relocated meter shop and fleet garage will be less than the cost of the office space that Enbridge will be vacating, since industrial building lease rates are 40% to 50% lower than office space lease rates.

iv. Enbridge has negotiated transportation and heavy work equipment pricing through a strategic sourcing initiative where savings are achieved through single sourcing with automobile manufacturers over a multi-year period, with savings based on volume discounts.

v. Minor increases or variations in fleet and equipment units over the 2014 to 2016 period will be accommodated through efficiencies in the management of the fleet and equipment inventory.

vi. Currently, compressed natural gas for vehicles is approximately 40 per cent less expensive than gasoline or diesel. The increased utilization of compressed natural gas for vehicles will improve efficiencies in the operation of the Company fleet. With vehicle manufacturers re-emerging in the production of natural gas powered cars and trucks as Original Equipment Manufacturers ("OEMs"), the availability of these vehicles will continue to increase the penetration of NGVs in the Company fleet.

VPC FUNCTIONAL ALIGNMENT PROJECT

PROJECT SUMMARY

The Company's Victoria Park Complex ("VPC") contains its head office, as well as a meter shop and fleet garage. The mixed uses at VPC were appropriate at the time the building was opened in 1968, but that is no longer the case. The fleet garage and the meter shop have remained at VPC and as office staff growth continued over the years, the mixed use nature of the site has become more problematic, primarily from a safety perspective. Moreover, the conditions of the meter shop and garage have deteriorated to the point where alterations and upgrades are required. In addition, since 2010, additional office space has been leased in two office towers adjacent to the VPC site to accommodate growth in office staff. Taking these items into account, the Company has determined that it is appropriate to relocate the meter shop and fleet garage to separate locations, which will then allow the space at VPC to be used more productively.

The VPC Functional Alignment Project (the "Project") is comprised of the following four activities:

1. Relocation of the meter shop to a leased property in 2014 - $3.55 million
2. Conversion of the vacated meter shop space into office space in 2015 - $2.1 million.
3. Relocation of the fleet garage to a leased property in 2015 - $3 million.
4. Expansion of the parking lot in 2016 - $550,000.

The total cost of the Project over 2014 to 2016 is $9.2 million. Planning and design work is underway.

The Project will achieve the following:

- Best safety model
- Lowest cost model
- All administration staff will be housed in one building
- Improved employee engagement

DESCRIPTION OF WORK

Overview of the Existing Victoria Park Complex (VPC) Site

The Company's head office is located at the intersection of Victoria Park Avenue and Consumers Road (in close proximity to Highways 401 and 404) with a municipal address of 500 Consumers Road. The property, owned by EGD, is mixed-use with office and industrial uses. The site consists of 15 acres of land and is improved with a five-storey suburban office tower, an adjacent single-storey industrial building and a freestanding industrial building (collectively, the "Property" or "VPC"). There are about 1,000 ground level parking spaces on the site. The three buildings within the Property total approximately 346,000 square feet ("sq. ft.") and are more than 40 years old.

The building structures include the following:

- VPC Tower – a five-storey (plus finished basement) suburban class B/C office building of approximately 225,000 with an average floor plate of 37,500 sq. ft. An original two-storey structure was built in 1968. Three additional floors were added in 1978.
- Annex/Link – a single-storey industrial building of approximately 86,000 sq. ft. linked to the Tower at grade level, housing office space, an industrial gas meter repair shop (the "meter shop") and the Ombudsman Customer Contact Center.

Approximately 52,000 sq. ft. is used as office space, while the meter shop is approximately 34,000 sq. ft. The Annex/Link structure was built in 1968.

- Fleet Garage Building – a freestanding single-storey 35,000 sq. ft. industrial building including a mezzanine and limited office space, utilized as a repair and service facility for Company-owned vehicles. The Fleet Garage Building is located at the west end of the Property and was built in 1968.

Issues with Current VPC Configuration

The mixed uses at VPC were appropriate when the time the building was opened in 1968 to about the early 1990s. The original administrative building concept with office, retail, service, operations, the meter shop, a warehouse and the fleet garage does not benefit the current organization structure as well today because the integration and proximity demands are not the same.

Over the years (specifically in the early 1990s) the warehouse was relocated to Markham in a downsized configuration, as retail and service was no longer part of the utility, and operations space was eliminated. The vacated space (all industrial) was converted to office space to maximize utilization of the Property and to accommodate growth in office staff at that time. However, the fleet garage and the meter shop have remained at VPC and as office staff growth continued over the years, the mixed use nature of the site has become more problematic, primarily from a safety perspective. The loading dock maintains an ongoing industrial operation which must be carefully aligned with the office use traffic (IT, furniture, etc.). The fleet operation includes operating heavy work equipment, community events and operations vehicles and heavy vehicle trailers in a common yard with the general office parking. While the various uses within VPC are maintained in a safe and managed state, the fluctuation and incompatibility of each operation to the other impacts the performance of both. In addition, the meter shop has very little connection to the remaining office space and the industrial activities within are problematic (forklift traffic in proximity to employee foot traffic).

The previous upgrade of the meter shop was successful in updating process and environmental equipment but changing business requirements will require additional alterations and upgrades to the facility. The 40 plus year old garage building has been upgraded over the years to meet minimum standards, but the structure, roof, windows, doors and building systems (HVAC and electrical) are not cost effective to replace as opposed to replacing the structure to current standards required for purposes of a maintenance and repair garage.

In addition, since 2010, additional office space has been leased in two office towers adjacent to the VPC site to accommodate growth in office staff. It would be advantageous to relocate those office space needs back to VPC.

The Project

Taking the items described above in account, the Company has decided to proceed with the Project, to relocate the meter shop and fleet garage and use the space at VPC for other purposes. The separation of the industrial uses from the primary use of an office property not only complements each operation but better utilizes the Property. The capacity of the administration office areas of the VPC building has been a constraint for a number of years but has now reached a point where a change is required.

The Project will involve the following three major activities planned for the 2014-2015 timeframe with the final stage being completed in 2016.

1. *Relocation of the meter shop to a leased property in 2014* - $3.55 million. This project is required to relocate the meter shop operation from its current VPC head office location to a more appropriate location in a leased facility. The meter shop industrial activities are currently landlocked within a predominantly office occupancy. There are several safety issues (including fork lift lanes crossing office space, transport truck traffic in the parking lot) regarding the mixed use nature of the VPC head office facility with both industrial and office functions on the same site. Once the meter shop is relocated, the vacated space at the VPC will be transformed into office space to accommodate both existing staff housed in nearby leased office space and forecasted staff growth at the head office, thus avoiding significant lease costs. A separate off site facility is planned, a move that furthers Enbridge's efforts to improve safety and usability of adjacent office

space. The existing HVAC system is expected to be reused in either the office repurpose project or in the new facility and most of the process equipment will be re-used and reconfigured to meet the current needs of the meter shop operation.

2. *Conversion of the vacated meter shop space into office space in 2015* - $2.1 million. Once the meter shop relocation project is completed, the vacated space will be transformed into office space to accommodate both existing staff housed in nearby leased office space and forecasted staff growth at the head office, thus avoiding significant lease costs and associated build out costs to occupy nearby office towers. An area of approximately 30,000 square feet will be renovated into offices utilizing Company standards of open space planning in a cost effective manner.

3. *Relocation of the Fleet Garage to a Leased Property in 2015* - $3 million. The fleet garage at the VPC head office services the entire GTA with a primary focus on Operations with heavy vehicles, construction equipment, pickup trucks and smaller support vehicles. The fleet operation also supports the installation and maintenance of NGV equipment and also needs substantial yard space for the maintenance, storage and retirement of assets. There are several safety issues regarding the mixed use nature of the VPC head office facility with both industrial and office functions on the same site. Over the years, demand for passenger vehicle parking has grown due to employee growth which has impacted the parking lot area available to the fleet garage. The integrated operation initiated in 1968 is no longer capable of accommodating the volume and specialized needs of the fleet operation in the same building built in 1968. The project plan is to secure a new building shell on a suitable site in an appropriately zoned vehicle repair area to meet their long term requirements as well as to retire the current

building. Investment of significant capital dollars to renew an inadequate and inefficient building shell on the existing site is not recommended.

4. *Addition of parking at VPC in 2016* - $.55 million. The final stage of this project will be completed in 2016 with the expansion of the parking lot at the VPC head office facility for $550,000. The project plan is to demolish the 45 year old fleet garage and construct a new parking lot in its place to meet the parking space requirements at the VPC head office. Over the past 15 years, approximately 50,000 square feet of warehouse and industrial space at the VPC Head Office facility has been converted into office environments, increasing occupant load on the entire site and in particular, the parking lot which has not been expanding and is now at capacity. The planned conversion of the vacated meter shop into office space in 2015 (which will add a further 30,000 square feet of office environment for 200 more occupants) will require additional parking spaces.

NEED

The capacity of the administration office areas of the VPC building has been a constraint for a number of years but has now reached a point where a change is required. The primary drivers behind the timing of this project are safety, cost savings, office space requirements, employee engagement and the capital costs required to bring the fleet garage up to acceptable standards.

Safety issues with having industrial uses at VPC:

- Forklift traffic in proximity to employee foot traffic
- Meter shop operations including a paint booth near office area
- The loading dock must be carefully aligned with the office use traffic
- Truck traffic in parking lot, limited turning radius

- Heavy work equipment, large vehicles, trailers in amongst employee parking

Cost Savings and employee engagement – The plan to create additional office and parking space at VPC will be cost-effective. This will allow the Company to reduce the amount of high-cost office space being leased, as employees currently in leased space can move back to the VPC site. By doing this, the Company can take advantage of the tenant common areas and support space that already exists at VPC, rather than paying for such amenities as part of the rent for the currently leased space. The cost of the leased space to house the relocated meter shop and fleet garage will be less than the cost of the office space that Enbridge will be vacating, since industrial building lease rates are 40% to 50% lower than office space lease rates. In addition, there will be benefits from having more of the Company's central administration and operations teams at the same site. Table 1 and 2 below provides a comparison of the cost of the space currently leased at Atria versus the leased space required to house the meter shop and fleet garage.

Table 1

Atria
Projected 2016 Lease Costs (including operating costs)

Floor	Square Footage	Lease Rate	Total Annual Cost	Number of Employees
Atria 1 – 4th Floor	32,570 sq. ft.	$36.21	$1,179,333.00	141
Atria 3 – 8th Floor	19,900 sq. ft.	$35.43	$705,123.00	82
Total	52,470 sq. ft.	$35.91	$1,884,456.00	223

Witnesses: D. Lapp
P. Rapini
R. Riccio

Table 2

Meter Shop and Fleet Garage
Projected 2016 Lease Costs (including operating costs)

Building	Square Footage	Lease Rate	Total Annual Cost
Meter Shop	34,000 sq. ft.	$14.50	$493,000.00
Fleet Garage	28,000 sq. ft.	$17.50	$490,000.00
Total	62,000 sq. ft.	$15.85	$983,000.00

Capital costs required to bring the fleet garage up to acceptable standards. The condition of the existing fleet garage building is both physically and functionally obsolete and in need of significant capital repairs and replacements to bring the building to acceptable standards. The following are some of the items that would have to be addressed:

- Roof
- Electrical and mechanical systems
- Windows and doors
- Heavy work equipment area is undersized
- Inadequate number and size of dedicated parking

ALTERNATIVES CONSIDERED

The only real alternative is the status quo. If a determination was made not to relocate the meter shop and fleet garage, then the Company would have to incur capital expenditures required to complete all of the repairs and replacements necessary to bring the fleet garage up to an acceptable standard, and would continue to lease space at Atria to house existing and planned growth in administration staff. It has been determined that the status quo option is more costly and does not eliminate the number of safety issues associated to the mixed uses at the VPC site.

COSTS

The forecast costs of the Project are the determined as follows.

1. *Relocation of the meter shop to a leased property in 2014* - $3.55 million.

Cost Category	Details	Estimated Cost
Design, Construction Documents and Permits		$350,000.00
Project Management		100,000.00
Equipment		235,000.00
Build and Fit-Up:		
• Mechanical	$500,000.00	
• Electrical	450,000.00	
• Architectural	1,135,000.00	
• Structural	460,000.00	2,545,000.00
Sub-Total		3,230,000.00
Contingency (10%)		320,000.00
Total Project Cost		$3,550,000.00

2. *Conversion of the vacated meter shop space into office space in 2015* - $2.1 million.

Cost Category	Details	Estimated Cost
Design, Construction Documents and Permits		$160,000.00
Project Management		50,000.00
Build and Fit-Up:		
• Mechanical	$450,000.00	
• Electrical	200,000.00	
• Architectural	950,000.00	
• Structural	100,000.00	1,700,000.00
Sub-Total		1,910,000.00
Contingency (10%)		190,000.00
Total Project Cost		$2,100,000.00

3. *Relocation of the Fleet Garage to a Leased Property in 2015* - $3 million.

Cost Category	Details	Estimated Cost
Design, Construction Documents and Permits		$195,000.00
Project Management		75,000.00
Equipment		635,000.00
Build and Fit-Up:		
• Mechanical	$700,000.00	
• Electrical	400,000.00	
• Architectural	500,000.00	
• Structural	225,000.00	1,825,000.00
Sub-Total		2,730,000.00
Contingency (10%)		270,000.00
Total Project Cost		$3,000,000.00

4. *Addition of parking at VPC in 2016* - $.55 million.

Cost Category	Estimated Cost
Design, Site Plan and Permits	$35,000.00
Project Management	15,000.00
Site Works (area to be paved 60,000 sq. ft.)	475,000.00
Sub-Total	525,000.00
Contingency (5%)	25,000.00
Total Project Cost	$550,000.00

Witnesses: D. Lapp
P. Rapini
R. Riccio

EGD Asset Plan

2013-2022

June 21, 2013

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1. Executive Summary

Enbridge Gas Distribution (EGD) is one of North America's oldest investor-owned, regulated natural gas distribution utilities. The Company owns, operates and manages over 36,000 km of pipelines, over 2 million services, over 14,000 stations, and other related distribution network assets required to service over 2 million customers.

As part of providing safe and reliable gas distribution services to its customers, the Company has to effectively manage two main challenges:

- Cost-effectively support customer growth of an estimated 36,000 to 40,000 new customer additions each year, while maintaining safe and reliable distribution of natural gas to existing customers
- Effectively respond to current and emerging system integrity and reliability issues

Over the past several years, EGD has been adopting an Asset Management System approach to further improve its capability to effectively address such challenges.

An Asset Management System is defined as a strategic management system used to optimally manage assets over their lifecycle by balancing performance, risk, and expenditures. Such a system is comprised of a number of processes.

Two of the key processes within the Asset Management System are the Asset Planning process and the Integrity Management process.

- The Asset Planning process identifies asset requirements over a specified period of time, and establishes the costs and plans to meet these requirements.
- The Integrity Management process identifies risks associated with assets, prioritizes these risks, and establishes appropriate mitigation plans to address these risks.

The Asset Planning process utilizes the Integrity Management process to identify asset requirements related to integrity and reliability.

The purpose of an Asset Plan is to define and communicate the condition of, and what needs to be done with the Company's assets over a specified period of time, the rationale behind these activities, and the investments needed for execution.

In May 2012, the Company developed the first version of its long term Asset Plan. This plan was a 10-year plan for the period of 2012-2021. The plan provided a description of anticipated distribution asset-related requirements and the related capital spend to support customer additions, reinforcements, relocations, and system integrity and reliability.

Utilizing the experience gained from conducting the first iteration of the Asset Planning and Integrity Management processes in 2011/2012, several changes have been introduced in this next version of the Asset Planning process and scope. The intent of these changes is to improve the quality and comprehensiveness of the Asset Plan for the period of 2013-2022.

When compared to the 2012-2021 Asset Plan, there are three types of changes to the Asset Plan for 2013-2022:

(a) Changes to the Asset Planning and Integrity Management processes
(b) Changes to the outcomes of the processes (i.e. asset requirements and related forecast of capital expenses)
(c) Changes to the Asset Plan documentation

A complete summary of these changes is included in section 2.4

This document summarizes the key outputs of the Asset Planning process, and provides an updated Asset Plan for the period of 2013-2022. It is not intended to represent a detailed 10-year budget.

There are primarily four categories of requirements that determine the overall plan for all the assets within the scope of the Asset Plan:

- Customer Additions
- Reinforcements
- System Integrity and Reliability
- Relocations

Customer Additions:

EGD has experienced significant customer growth in its franchise area. This growth is forecast to continue in the future, as shown in the chart below. The annual number of new customer additions is expected to be in the 36,000 to 40,000 range for the term of the Asset Plan. These new customer additions will require the construction and installation of mains, services, meters, regulator stations and the associated equipment.

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. Investments required to reinforce the distribution system are primarily driven by customer growth and system integrity and reliability considerations. As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up EGD's franchise area.

The analysis determined that a significant increase in reinforcement investment is required over the 10 year horizon of this Asset Plan. Approximately 40 such reinforcement projects have been identified.

In addition to several routine reinforcements, two major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system serving the GTA and Ottawa areas are required to further support customer growth and address significant system reliability and security of supply issues.

System Integrity and Reliability:

System Integrity and Reliability captures a category of spending focused on:

- Maintaining the natural gas distribution pressurized system at or above adopted standards for safety and operational effectiveness (System Integrity)
- Ensuring the dependable delivery of natural gas to EGD's customers and end-users (Reliability)

A critical responsibility in managing a natural gas distribution system is to understand potential threats to the safety and reliability of the system. Threats to the system can manifest risks defined as a combination of likelihood and impact, which if not appropriately managed, can lead to serious incidents.

EGD has been evolving its Integrity Management processes towards a more rigorous, risk-based decision making approach within the context of a comprehensive Asset Management System. Several drivers, including industry trends and developments, legislation, advancements in gas pipeline inspection technology, and the evolution of EGD's Asset Management discipline are contributing to EGD's evolving Integrity Management process.

In summary, this evolving Integrity Management approach is intended to help ensure that EGD can continue to comply with current and future regulations and that EGD is constantly working to continue to minimize the possibility of high-consequence events in a prudent manner over time. The Company believes that this is what is expected by its customers, regulators and the public.

In the previous iteration of the Integrity Management process, approximately 35 system integrity and reliability risks were identified. As the Integrity Management process has evolved, the risk assessment process was enhanced to be more comprehensive and thorough. This enhanced process was used in the current Asset Planning process, and resulted in approximately 59 system integrity and reliability risks being identified. Using last year’s list of risks as a starting point, multiple working groups of Subject Matter Advisors (SMAs) were engaged in more focused and detailed discussions on risks. In addition to validating last year’s list of risks, these discussions identified an additional set of risks.

Over 45 initiatives have been identified to address these risks. A number of these initiatives will start out as studies since some of the risks require further study and analysis in order to design, scope and plan programs to mitigate them.

The timing, scope and pace of the system integrity and reliability initiatives are based on the relative risk ranking, project interdependencies, current work in progress and operational capacity.

Some of the key programs that have been identified to address system integrity and reliability risks are:

- Replacement of AMP fittings
- Verification of the Maximum Operating Pressure (MOP) of lines operating over 20% Specified Maximum Yield Strength (SMYS)
- Study and replacement of vintage plastic mains
- In Line Inspections (ILI) and assessment of pipelines operating over 20% SMYS
- Enhancement of distribution asset records
- Replacement of stations

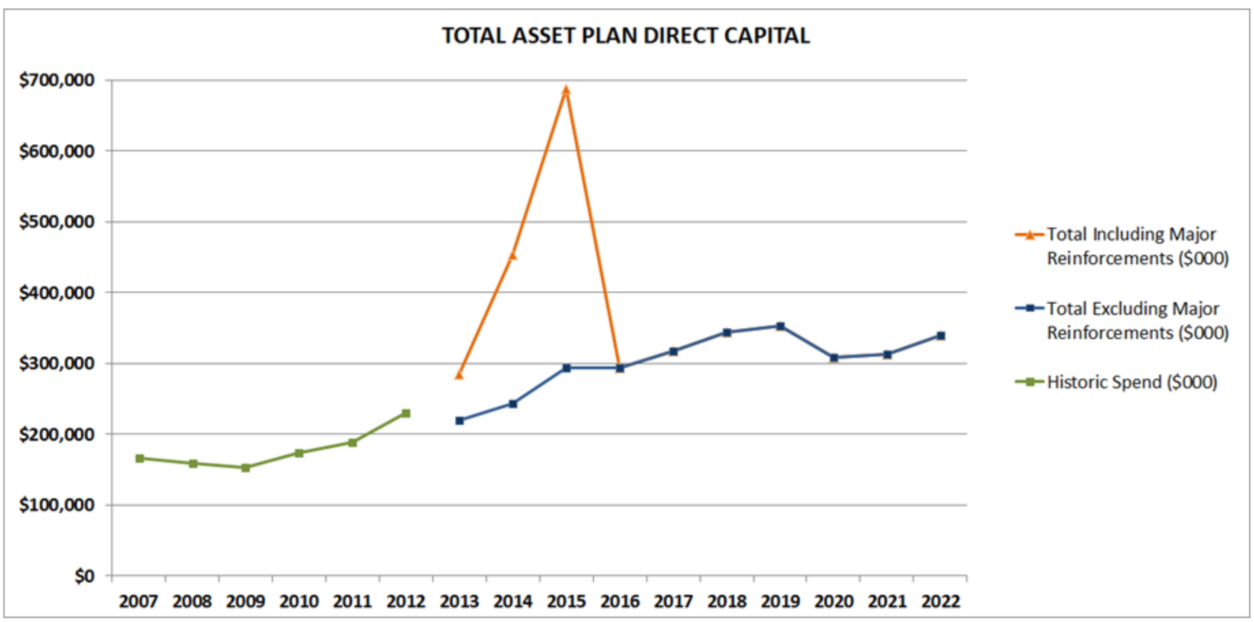
Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects.

In forecasting future years' relocations, EGD begins with the historical level of relocation activity and then adds projects or programs identified as incremental to that historical level. Within the 10 year horizon of this Asset Plan, a number of incremental activities, which are already underway or announced, are driving forecast relocation costs above historical levels. These activities include major transit projects (Toronto Transit Commission (TTC) Subway expansion, Greater Toronto Airport Authority (GTAA) Rail Link, Rapid Transit – Eglinton Light Rapid Transit (LRT), York Region Rapid Transit, and Ottawa LRT), major road expansions (407 extension) and preparations for the 2015 Pan Am Games.

Forecast Capital Cost of the Asset Plan

The following chart summarizes the estimated direct capital costs that are required to effectively meet the customer additions, reinforcement, system integrity and reliability, and relocation requirements included in the Asset Plan, as compared to the historic spend. A 2% inflation factor has been assumed for the period of 2014 to 2022. The costs shown below do not include overheads.



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Excluding Major Reinforcements ($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$221,331	$219,794	$242,806	$293,082	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155
Total Including Major Reinforcements ($000)	$166,355	$158,783	$152,971	$172,927	$189,062	$230,069	$284,511	$453,176	$687,134	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155

Chart 1 : Summary - Total Asset Plan Spend

Since the Asset Plan assesses long term asset requirements at a particular point in time, there is recognition that these requirements and the estimated expenditures related to them may change year over year as circumstances change. Examples of such changes include changes in the economic landscape which affect forecasted demand for new customer additions, new or modified technical standards or codes, discovery of new system integrity and reliability risks such as equipment failure rates, and elevated levels of municipal activities or infrastructure projects that result in relocation of gas distribution assets.

2. Introduction

2.1 Background and Context

In 2012, EGD hit an important milestone by reaching the 2 million customer mark. The Company owns, operates and manages over 36,000 km of pipelines, over 2 million services, over 14,000 stations, and other related assets.

With a forecast of 36,000 to 40,000 new customer additions expected each year, one of the Company's major challenges is to continue to cost effectively support this customer growth while maintaining safe and reliable distribution of natural gas to existing customers.

Another major challenge for EGD is responding to current and emerging system integrity issues. Following some major incidents in the United States in recent years, in particular, the pipeline rupture and subsequent explosion near San Bruno California, the entire natural gas industry, including regulators and legislators, has a heightened awareness and sensitivity to the integrity of its natural gas transmission and distribution systems. These incidents have generated new and emerging legislative requirements in the United States and Canada. As a prudent utility, EGD (along with other industry members) is striving to better understand the condition of its assets, to better understand and assess risks associated with its assets, and proactively initiate mitigation programs to effectively manage these risks.

Over the past several years, EGD has been adopting an Asset Management System approach to further improve its capability to effectively address such challenges.

An Asset Management System is defined as a strategic management system used to optimally manage assets over their lifecycle by balancing performance, risk, and expenditures. Such a system is comprised of a number of processes.

Two of the key processes within the Asset Management System are the Asset Planning process and the Integrity Management process.

- The Asset Planning process identifies asset requirements over a specified period of time, and establishes the costs and plans to meet these requirements.
- The Integrity Management process identifies risks associated with assets, prioritizes these risks, and establishes appropriate mitigation plans to address these risks.

The Asset Planning process utilizes the Integrity Management process to identify asset requirements related to integrity and reliability.

In May 2012, the Company developed the first version of its long term EGD Asset Plan.

The Asset Planning process has helped provide an additional level of engineering and operational input and diligence into the process of anticipating asset-related requirements and developing effective operational and financial plans to address them. The 2012-2021 Asset Plan was filed as evidence to support EGD's 2013 rate case filing with the OEB.

Since the Asset Plan assesses long term asset requirements at a particular point in time, there is recognition that these requirements and the estimated expenditures related to them may change year over year as circumstances change. Examples of such changes include changes in the economic landscape which affect forecasted demand for new customer connections, new or modified technical standards or codes, discovery of new system integrity and reliability risks such as equipment failure rates, and elevated levels of municipal activities or infrastructure projects that result in relocation of gas distribution assets.

The 2013-2022 Asset Plan is an update to the 2012-2021 Asset Plan. In addition to some changes to the Asset Planning process, the outcomes of the process have also been updated. Section 2.4 provides an overview of the changes to this iteration of the Asset Planning process.

2.2 Purpose and Objectives of the Asset Plan

The purpose of an Asset Plan is to define and communicate the condition of, and what needs to be done with the Company's assets over a specified period of time, the rationale behind these activities, and the investments needed for execution. The needs of the assets should be considered over their entire life cycle including creation or acquisition, operation, maintenance and decommissioning.

EGD's Asset Plan forecasts the Company's distribution asset requirements and related spending priorities over a 10-year period (2013-2022).

More specifically, the objectives of this Asset Plan are:

- Align asset-related activities with the Company's key areas of focus including safety, reliability, risk management and customer satisfaction
- Provide inputs to the Company's long term planning, resourcing and budgeting processes

- Serve as a mechanism to communicate EGD's asset management priorities and planned investments with internal and external parties including EGD's regulators

The target audience of the Asset Plan includes EGD's Senior Management, Operational Managers, and others including external parties such as the Ontario Energy Board (OEB) and other applicable stakeholders.

The Company intends to develop its Asset Plan on an annual basis as part of its annual long-range planning process, and to utilize it as a starting point to inform its annual budgeting process. The Asset Plan will serve as a key input to establishing the Company's work priorities and resource requirements, and will inform the Company's budget process.

Since asset requirements and circumstances change over time, it is not always possible to accurately estimate and predict asset-related requirements and capital expenses over a long period of time. Hence, EGD's Asset Plan is intended to serve as a planning tool to proactively understand requirements for the future, and help forecast and plan work, and related capital expenditures over a 10-year period. It is not intended to represent a detailed 10-year budget.

The Asset Plan informs the budgeting process for EGD and supplements the evidence to be filed by the Company.

2.3 Scope of the Asset Plan

The following are the key elements that define the scope of this Asset Plan:

Items within the scope of the 2013-2022 Asset Plan:

- The planning horizon for the Asset Plan is 10 years, 2013 to 2022
- The Plan is limited to the following distribution assets owned and operated by EGD across all regions within its franchise area:
    - Pipe – Mains
    - Pipe – Services
    - Fittings
    - Valves
    - Stations, meters and all other measurement and regulation equipment
- All expenses included in the plan are direct capital costs only
- An inflation factor of 2% annually has been included starting in 2014

Items not included within the scope of the 2013-2022 Asset Plan:

- The plan does not include the following assets that are owned and operated by EGD:
  - Gas storage assets at EGD's Tecumseh storage facility
  - Facilities (such as buildings)
  - Equipment and fleet
  - Information technology assets (such as computer hardware and software)

2.4 Changes from the 2012-2021 Asset Plan

When compared to the 2012-2021 Asset Plan, there are three types of changes to the Asset Plan for 2013-2022:

- Changes to the Asset Planning process
- Changes to the outcomes of the process (i.e. asset requirements and related forecast of capital expenses)
- Changes to the Asset Plan documentation

Changes to the Asset Planning Process:

As part of the continuous improvement cycle, EGD intends to continue to improve its Asset Planning process. The intention of these improvements is to enhance the quality and value of the Asset Plan. Utilizing the experience gained from conducting the first iteration of the Asset Planning process in 2011/2012, the following changes have been introduced while developing this iteration of the Asset Plan for 2013-2022

1. Process to assess system integrity and reliability requirements:
   This is the area where the Asset Planning process has changed the most from the last iteration of the plan. Refer to section 5.4 for a more detailed description of this process. The key changes include:
   - Risk Identification and Validation : Multiple focus groups of cross-functional subject matter advisors from within the Company were consulted to identify and validate risks associated with individual asset classes and issues, i.e. Reliability of Supply; Records Integrity; Customer Service
   - Risk Evaluation and Prioritization: A more comprehensive approach has been used to evaluate risks based on best, likely and worst-case scenarios. A statistical approach

(double triangular distribution) was used to aggregate the risk of each scenario into an overall risk level

2. **I**nclusion of Inflation within capital cost estimates:

An annual inflation factor of 2% has been included for all direct capital costs in 2014 and beyond. By including inflation within the estimates, the forecast spend can be better compared against historic expenditures that inherently include inflation. Moreover, the compounding effect of applying inflation also provides a more reasonable trend in future expenses.

Changes to the Asset Requirements and Estimated Costs:

A key part of the Asset Plan is the assessment of future asset-related requirements and the estimate of the capital expenses related to them. Over time, asset requirements and estimated costs change.

There are three main factors that affect such changes:

(1) Changes in business circumstances, such as customer addition forecasts, new legislation, or changes in cost drivers (labour, material, etc.)
(2) Changes to the Integrity Management and Asset Planning processes
(3) Changes in Asset Management policies or strategies

The following are the key changes in the 2013-2022 Asset Plan that are related to the factors above

- Customer Additions
  - The 10-year forecast for customer additions has been updated from last year
  - The unit costs have been updated to be consistent with actual spend in 2012
- Reinforcements
  - Reinforcement requirements have been updated to reflect changes in customer additions forecasts and locations
  - The timing and costs of reinforcement projects have been adjusted to reflect reinforcement requirements and feasibility of completing construction activity
- System Integrity and Reliability
  - As a result of applying the enhanced process for risk identification described above, the number of risk items in the risk register has grown

    - Revisions to the risk evaluation process have resulted in changes to the distribution of risks within the four risk priority categories
    - As more information is available on risks, the number, composition, cost and timing of programs to address these risks has evolved
  - Relocations
    - Relocation expenses have been updated to reflect more recent information on the scope and timing of specific transit projects that influence EGD's relocation requirements

Changes to Asset Plan documentation

In order to enhance the readability and completeness of the Asset Plan, a few changes have been made to the level of detail and format of the content within the Asset Plan document.

The following are the key changes:

- Description of customer addition requirements
    - A map has been included to visually depict the comparison of expected customer growth in each of EGD's operational areas
- Description of reinforcement requirements
    - Further detail has been included on the description of individual reinforcement projects
    - Since the majority of reinforcements are required to support customer growth, relevant maps have been included to show the location of proposed segments of the distribution system that need to be reinforced and key locations within the franchise area where customer growth has been forecasted. The intention of these maps is to visually support the description of reinforcement projects
- Additional detail to provide better context and description of the process used to establish asset requirements and related capital costs

2.5 High Level Overview of EGD's Asset Planning Process

Based on industry practices and internal expertise, EGD has developed, adapted and employed its own Asset Planning process.

The Asset Planning process is an annual process that provides a rolling 10-year update to the Asset Plan developed in the previous year.

At the high level, this is a four-step process that can be summarized as follows.

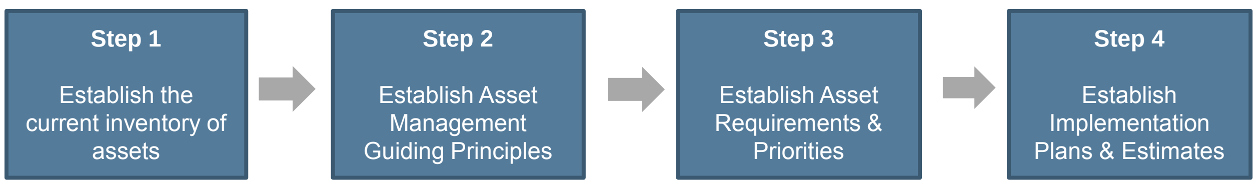


Figure 1 : High Level Asset Planning Process

Step 1: Establish the Current Inventory of Assets:

The distribution system is comprised of thousands of discrete components. To analyze and determine the needs of the assets, it is necessary to develop an appropriate classification for those assets, and inventory those assets by class rather than try to deal with discrete components.

- Based on the scope of the Asset Plan, a suitable "Asset Classification" is established that identifies the key assets, and classifies them into a hierarchy
- Using the Asset Classification as a reference, an inventory of assets is established. This represents a count of the key assets within the asset hierarchy
- Information on the asset inventory is supported by an explanation of relevant details on each class of asset, such as its age distribution and material type

Step 2: Establish Asset Management Guiding Principles:

- Guiding principles provide the basis and rationale for Asset Management decisions
- These principles include Asset Management objectives, policies, and strategies

- These principles are used to guide the development of the Asset Plan, more specifically with respect to the identification of requirements, their prioritization, and definition of plans to address requirements.

Step 3: Establish Asset Requirements and Priorities:

When considering asset requirements and priorities, it is necessary to consider the various types of asset investments that are required to build, operate and maintain the distribution system.

- Considering the various types of asset investments, there are four primary categories of requirements that determine the overall Asset Plan:
    a. Customer Additions
    b. Reinforcements
    c. System Integrity and Reliability
    d. Relocations
- The approach to establishing these requirements and prioritizing them varies by category
- In general, the requirements and priorities are determined based on a variety of information, including asset condition data from operational systems, forecasts, tacit knowledge, and historical information

Step 4: Establish Implementation Plans and Estimates:

- The implementation plan forecasts the scope and timing of asset-related projects, programs and investments that are needed to meet the asset requirements and priorities
- Capital investments needed to support the execution of the implementation plans are estimated by using a variety of approaches as appropriate, including historical expenditures and unit costs where available

3. Overview of EGD's Distribution Assets

This section provides an overview of how EGD classifies distribution assets, an inventory count, geographic distribution, and age-related profiles. It will provide the context for the discussion on system integrity and reliability requirements, strategies and plans in section 5.4.

3.1 Asset Classification and Inventory

EGD's distribution assets have been classified into four classes – Pipe, Fittings, Measurement and Regulation equipment including stations, and Valves. A further level of categorization has been done based on the sub-type of assets by material type or function. Figure 2 below is a depiction of the asset hierarchy.

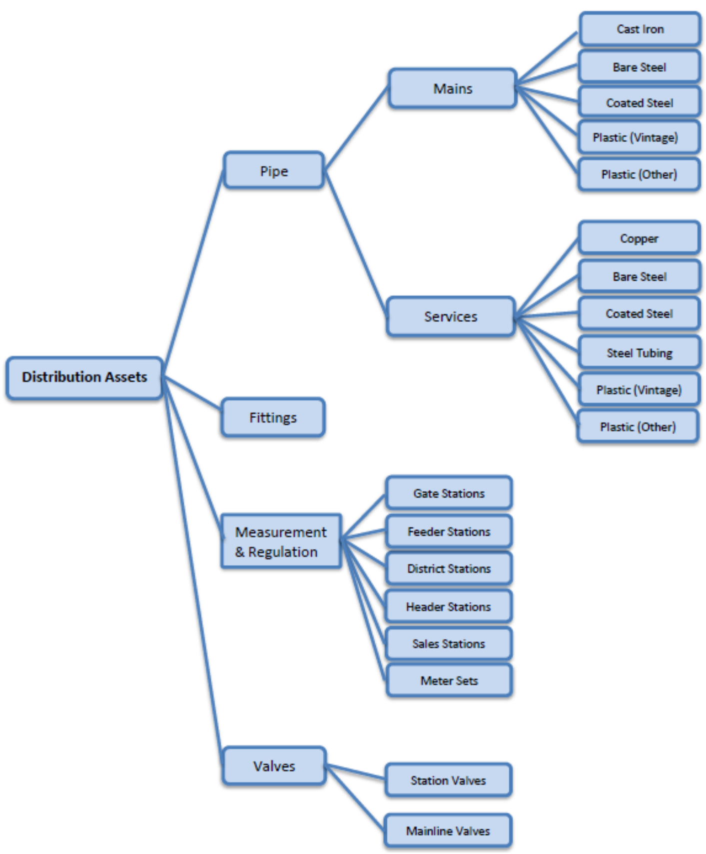


Figure 2 : Asset Classification

Based on the Asset hierarchy above, Table 1 below quantifies the assets, as of March 2013.

Distribution Asset Classes		Quantity
Pipe		
Mains (km)		**36,665**
	Bare Steel	3
	Coated Steel	13,128
	Plastic - Vintage	3,760
	Plastic - Other	19,774
	Unclassified	-
Services (#)		**1,998,682**
	Copper	7,063
	Bare Steel	29,317
	Coated Steel	154,797
	Steel Tubing	283
	Plastic - Vintage	283,523
	Plastic - Other	1,523,680
	Unclassified	19
Measurement & Regulation		
Gate Stations (#)		44
Feeder Stations (#)		19
District Stations (#)		2,118
Header Stations (#)		2,549
Sales Stations (#)		9,991
Customer Meter Sets (#)		2,098,342
Main & Station Valves		
Main Line Valves (#)		20,527
Station Valves (#)		11,200
Unclassified		8

Table 1 : Asset Inventory

A common reality faced by the natural gas industry is legacy records where some information about the asset that would be instructive to have is not available. In many cases this is because collection of specific types of data was not part of the records collection standard at the time of installation.

Where adequate information was not available to accurately classify the assets, they have been labeled “Unclassified”.

Although fittings are recognized as an important element of EGD's asset inventory, historically these have not been recorded as separate assets, but rather associated with pipe assets. This makes it difficult to determine a precise inventory of these assets.

3.2 Geographic Distribution of Assets

EGD's franchise area is divided into seven administrative areas (Areas 10, 20, 30, 40, 50, 60, 80) as shown below. All of EGD's distribution assets reside in these areas.

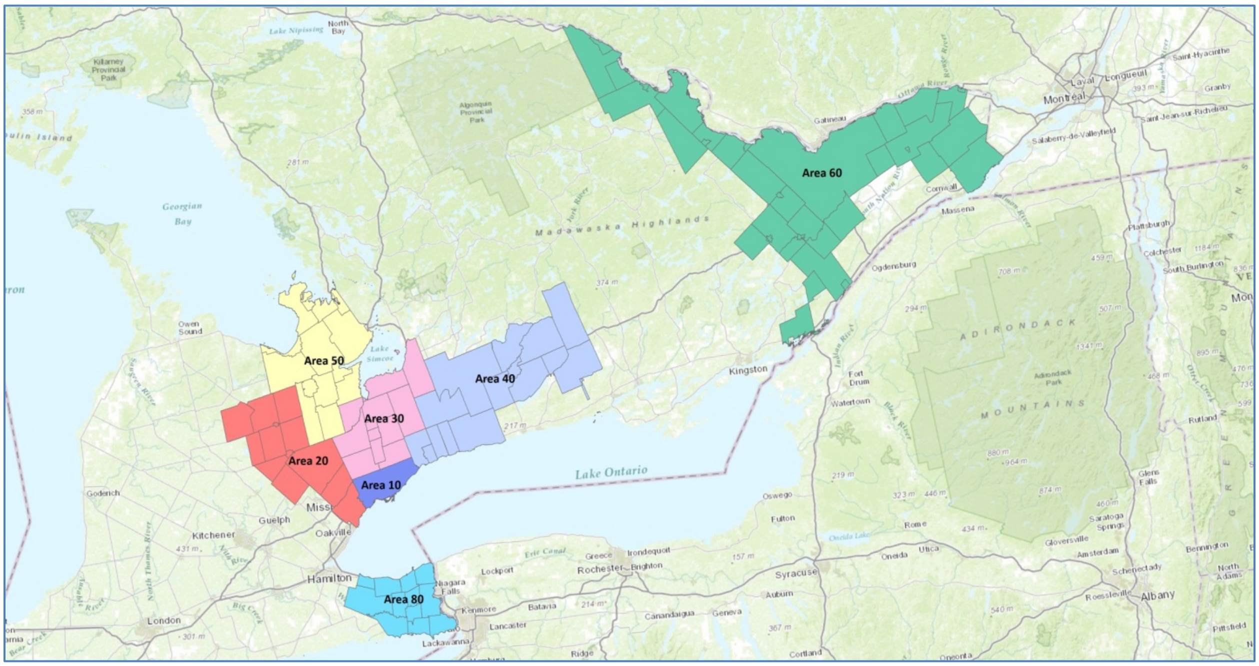


Figure 3 : EGD's Geographic Organization

Area 10 covers Toronto. Areas 20, 30, 40 and 50 cover the remainder of the Greater Toronto Area (GTA). Area 60 covers Ottawa and the surrounding region, and Area 80 covers the Niagara region.

Asset requirements can vary by area based on historic and future customer growth trends, historic regional practices, geographical conditions such as topography, soil condition, and other factors.

The asset inventory outlined in Table 1 is an aggregate of assets by asset class across all areas.

3.3 Understanding Assets by Age

EGD, as Ontario's oldest natural gas utility, has assets of varying age. Understanding the in-service date of the assets is important since materials degrade, and the performance characteristics of the assets can change over time. This understanding can help inform the need, scope and timing of replacement programs.

Histograms of mains, services and main/station valves based on age follow.

Mains:

EGD's distribution system has over 36,000 km of mains. Based on when these assets were installed and their material type, there are different generations or distributions of mains as shown in the chart below.

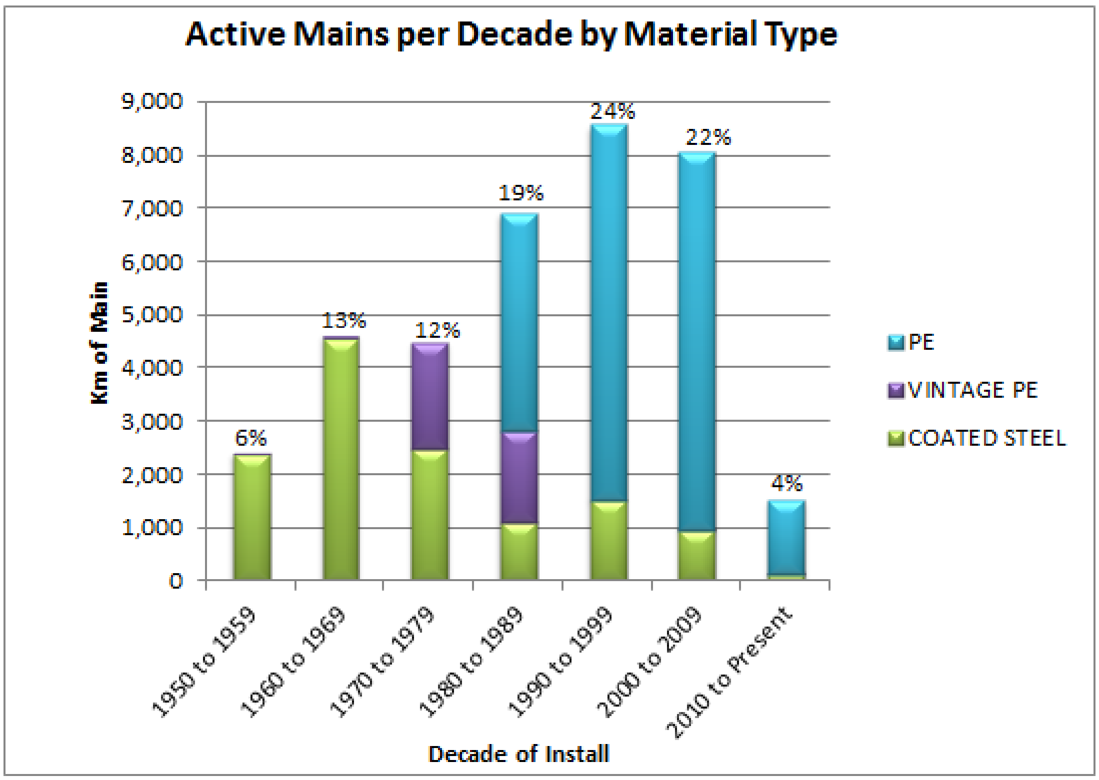


Chart 2 - Active Mains Installed by Decade by Material

The percentage number shown above each bar in the chart above indicates the quantity of mains installed in the corresponding time period, as a percentage of the total km of distribution mains in place today. Approximately 50% of current distribution mains were installed after 1989. The majority of these new mains were modern polyethylene (PE).

Services:

There are approximately 2 million active services across the franchise area. Similar to mains, there are several generations or distributions of services, based on their material type as shown in the chart below.

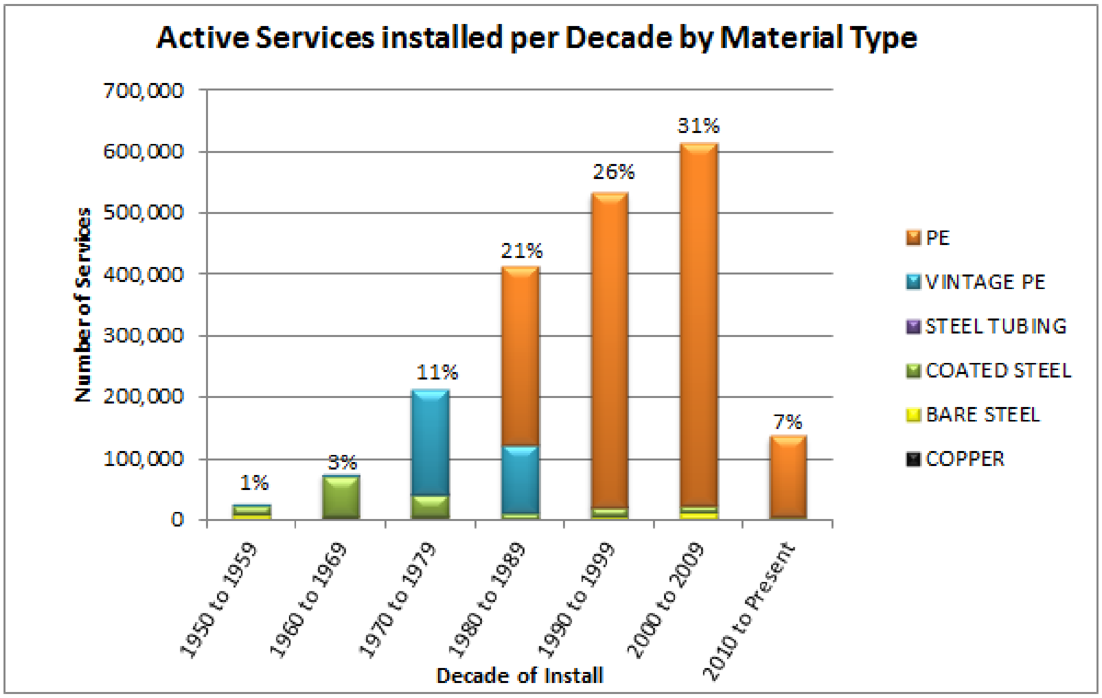


Chart 3 - Active Services Installed by Year by Material

Percentages shown above each bar in the chart above indicates the number of services installed as a percentage of the total number of services currently in place.

Main and Station Valves

There are approximately 31,000 active main and station valves across the franchise area. Approximately 95% of these valves are steel, with the remaining 5% being plastic. These valves are located in system pressure regulating facilities, in-line in mains, as well as at customer sales stations. Similar to mains and services, there are several generations or distributions of valves as depicted in the chart below.

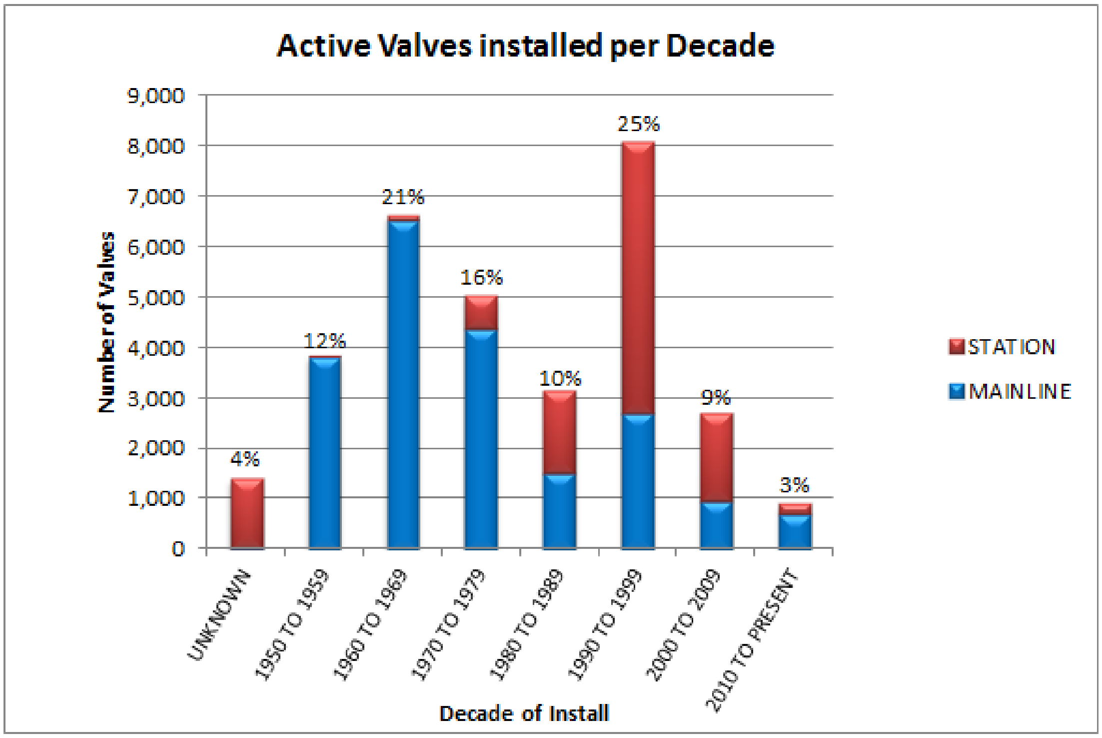


Chart 4 : Main and Station Valves by Category and Install Year

Percentages shown above each bar in the chart above indicates the number of valves installed as a percentage of the total number of valves currently in the system.

4. EGD's Asset Management Principles

As part of EGD's Asset Management System, several guiding principles have been developed. The principles are expressed as objectives, policies, and strategies. These principles have been used to guide the development of the Asset Plan, more specifically with respect to the identification of requirements, their prioritization, and definition of plans to address requirements.

4.1 Asset Management Objectives

The overall purpose of EGD's Asset Management process is to optimize the long term effectiveness and viability of its distribution assets by achieving an effective balance of risk, operational performance and cost.

The specific objectives to be considered are:

- Public and Worker Safety : Continue to drive to zero incidents and property damage
- Reliability of Service to Customers : Proactively identify and address asset related risks that can result in disruption of gas distribution services
- Customer Satisfaction : Leverage assets to provide appropriate levels of utility service to customers
- Customer Growth: Expand the distribution system to meet the growth in EGD's customer base in a sustainable manner
- Cost Effectiveness : Make prudent asset investment decisions
- Environmental Stewardship : Effectively manage the lifecycle of the Company's assets to reduce their environmental impact
- Compliance : Meet all applicable industry and regulatory requirements related to the management of assets
- Corporate Reputation: Protect and enhance the Company's reputation

4.2 Asset Management Policies

EGD is committed to the safe, reliable, cost effective and environmentally responsible provision of gas distribution and service. At the core of this commitment is the effective stewardship of the Company's distribution assets. It is through these assets that the Company ultimately provides value to its stakeholders.

Asset Management policies define the key considerations that should apply to ensure the effective management of the Company's assets

The following are policies that EGD has established to effectively manage its distribution assets:

1. The Company is committed to prudent decision making for all asset-related investments on the basis of risk, operational performance and cost
2. The Company is committed to the regular assessment of risks associated with its assets, and ensuring that these risks are effectively managed
3. The Company acknowledges that asset information is critical to the effective management of its assets. Therefore, the Company shall work to ensure that its processes, systems and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate and accessible asset information
4. The Company shall review, revise and ratify its Asset Plan on an annual basis
5. The Company is committed to managing every stage in the lifecycle of its assets in compliance with all applicable laws and regulations, industry codes of practice, and internal Company policies

4.3 Asset Management Strategies

Asset Management strategies define the high level approach to meet the Asset Management objectives, consistent with the Asset Management policies

The following table summarizes the high level strategies that have been developed by the Company to address the asset requirements included in this Asset Plan.

Type of Investment	Strategies
Customer Additions	• The strategy for customer additions is to add all customers in existing and new communities that meet regulatory obligations and feasibility guidelines
Reinforcements	• Reinforce existing distribution assets to ensure that the system has the capacity to reliably meet current and future customer load demand • Ensure security of supply by enhancing the flexibility of the system to address disruptions in upstream supply or failures with major components of the system
System Integrity and Reliability	• Replace existing assets that are near the end of their practical life • Conduct studies to improve understanding of the condition of specific classes of assets where risks have been identified. Leverage these studies to develop mitigation plans, including risk prioritized replacement, repair or monitoring programs • Comply with all applicable rules and regulations related to system integrity and safety • Enhance the integrity of distribution asset records to reduce operational risk • Enhance the Company's understanding of the condition and operating limits of its critical assets through a prioritized inline inspection program and MOP (Maximum Operating Pressure) verification consistent with industry practices • Protect the distribution assets from damages and corrosion through enhanced monitoring, installation of protective

	equipment, and the implementation of related programs • Enhance System Design standards to reduce the impact of failures and to minimize the impact of planned or unplanned service disruptions • Continue with existing programs already in place to address operational and asset risks and compliance requirements
Relocations	• The need to relocate EGD assets is primarily driven by external parties such as municipal authorities. EGD's strategy is to meet these relocation requirements in the most cost-effective way while recovering costs allowed by franchise and other agreements

Table 2 : Asset Management Strategies

5. Asset Management Requirements

This section of the Asset Plan defines:

- The known, and anticipated requirements related to EGD's distribution assets
- The approach to fulfill these requirements, consistent with the Company's Asset Management objectives, policies and strategies
- Estimates of the financial investments needed to meet these requirements

5.1 Overview of Requirements

The following diagram depicts the four primary types of asset-related capital investments that are required over the term of the Asset Plan.

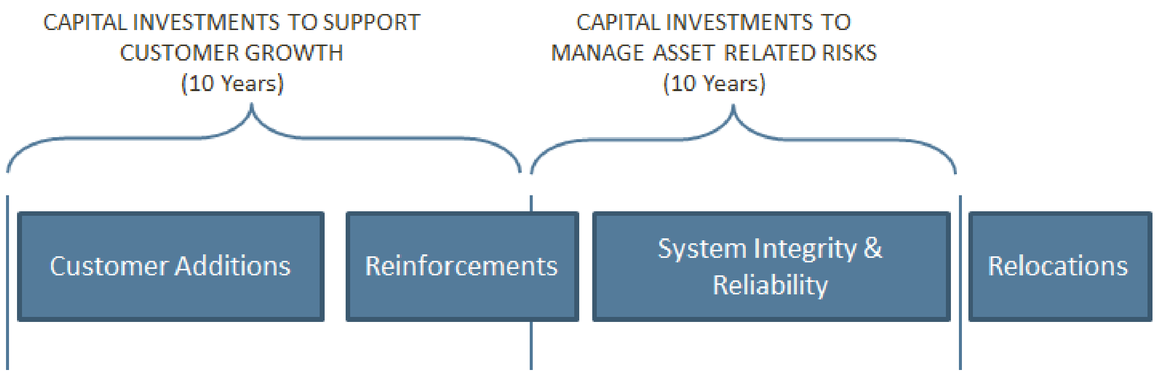


Figure 4 : Types of Asset Related Capital Investments

Customer Additions:

EGD is obligated to meet its customer growth demand by attaching customers that meet feasibility guidelines. Each year, there are several thousand customer addition projects that accomplish this. Customer addition projects typically involve installing new segments of main, installing services, and related meter sets.

In some cases, new measurement and regulation equipment such as stations need to be added or existing equipment needs to be upgraded due to load growth.

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. They primarily refer to mains. These projects are driven by customer growth and/or system integrity and reliability requirements.

System Integrity and Reliability:

In order to ensure safety and reliability, assets need to be effectively monitored, and risks need to be addressed in a proactive manner. There are a number of programs currently in place that address known risks. As new risks are identified, existing programs may need to be amended, or new programs may need to be established. Before amending existing programs or establishing new programs, studies may be necessary to validate the requirements.

Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects. The requirement and timing for these relocation projects is primarily driven by municipal authorities. EGD recovers a portion of the capital investments for such projects from those third parties.

5.2 Customer Additions

Introduction

Customer addition projects are associated with the construction and installation of mains, services, meters, regulator stations and the associated equipment to facilitate the connection of new gas customers within the EGD franchise area. These customers include residential subdivision, residential replacement, commercial, apartment buildings and industrial customers.

Each year, the Company develops a 10-year customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting, as well as municipal long term plans

This forecast helps the Company to determine the long term system planning needs, including segments of the distribution system that need to be reinforced. The forecast is also used within the Asset Planning process to develop estimates of capital expenses for customer addition projects over the term of the Asset Plan.

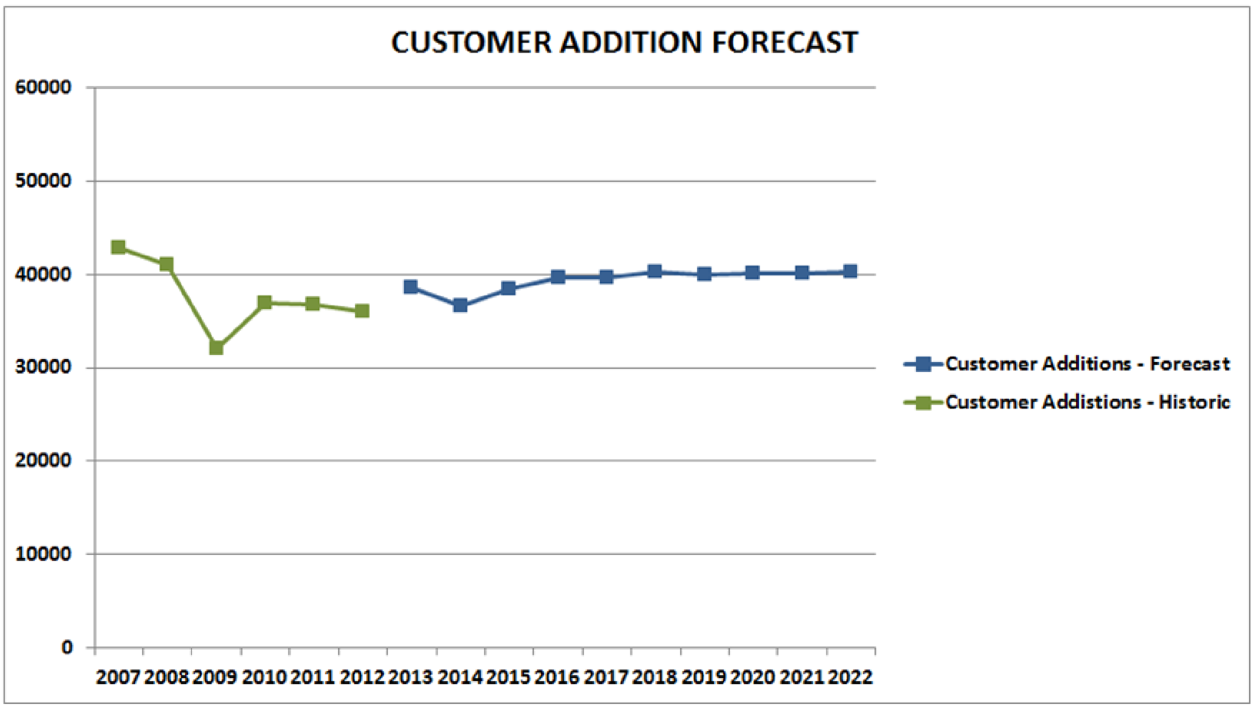
Generally, there are three components of capital investments needed to support the customer addition requirements:

- Installation costs related to mains, services and meters
- Material costs related to mains, services and meters
- Cost related to measurement and regulation equipment required to support customer growth

Based on these components of cost, unit costs are applied to the 10-year forecast to estimate the 10-year capital spend for customer additions within the Asset Plan.

Requirements

EGD has experienced significant customer growth in its franchise area. This growth is expected to continue in the future. The following chart depicts the historic customer additions and the forecast for the term of the Asset Plan.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
42920	41052	32089	36902	36753	35971	38579	36647	38489	39645	39715	40307	40040	40063	40072	40227

Chart 5 : Customer Additions Forecast

Between 2009 and 2012, EGD's annual customer additions rose from approximately 32,000 to 36,000 new customers per year. Based on forecasts, this higher level of customer additions is expected to continue for the next few years.

In 2013, the Company expects to add approximately 38,000 new customers. The number is then expected to dip in 2014 to approximately 36,000 new customers. This is because the majority of new customer addition requirements come from the new construction sector, which follows trends in the housing market. Relative to 2013, housing starts are projected to decline in 2014, followed by a pick-up in later years.

By 2016, the number of customer additions is expected to rise to approximately 39,000 new customers. The forecast then stabilizes to approximately 40,000 new customers for 2017 to 2022.

The source for the majority of these new customer additions is new subdivisions, many of which are located in suburban communities beyond the boundaries of the currently developed areas of the GTA and Ottawa.

The following map visualizes the forecast growth within EGD's franchise area over 2013 to 2022.

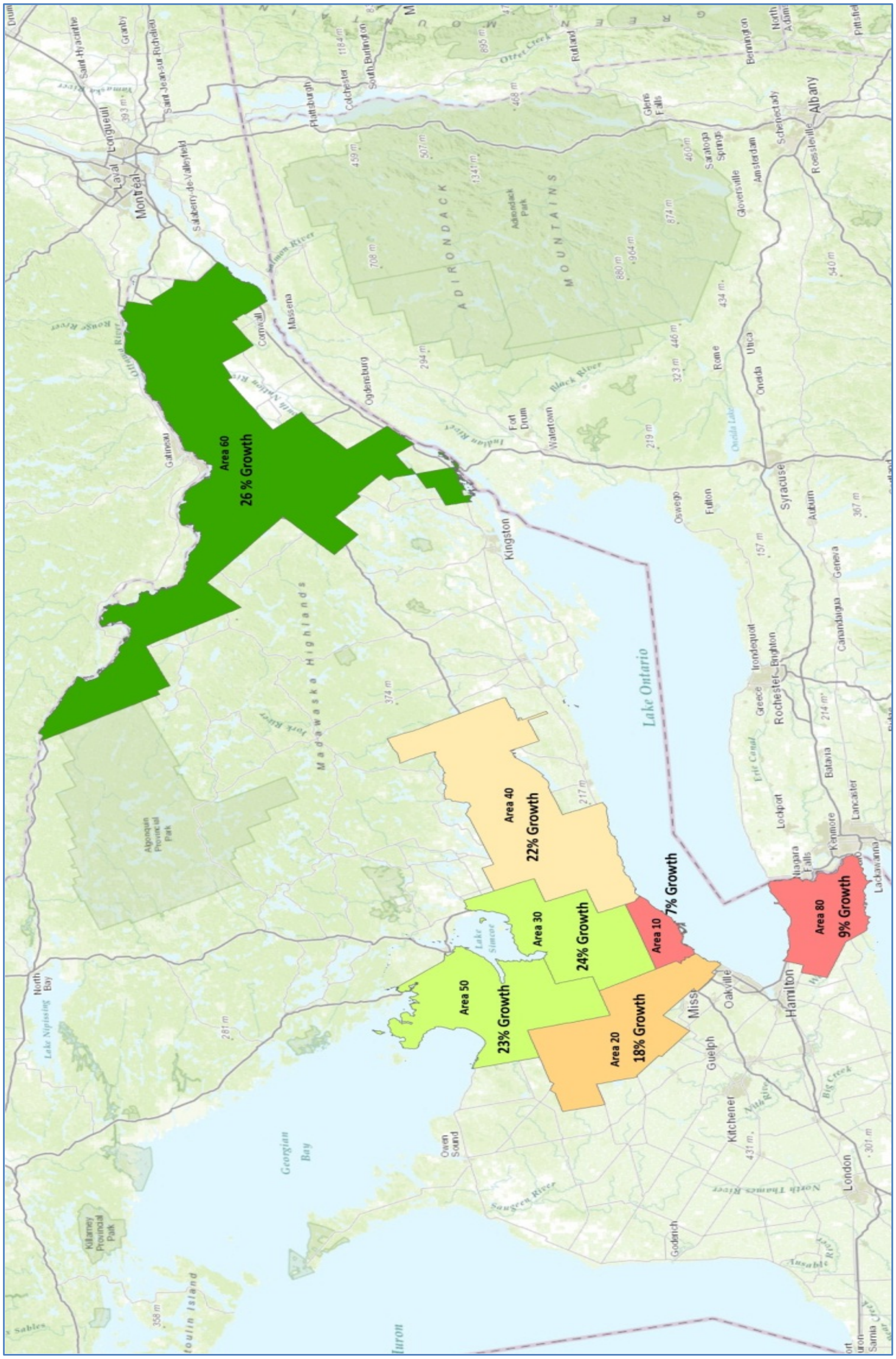
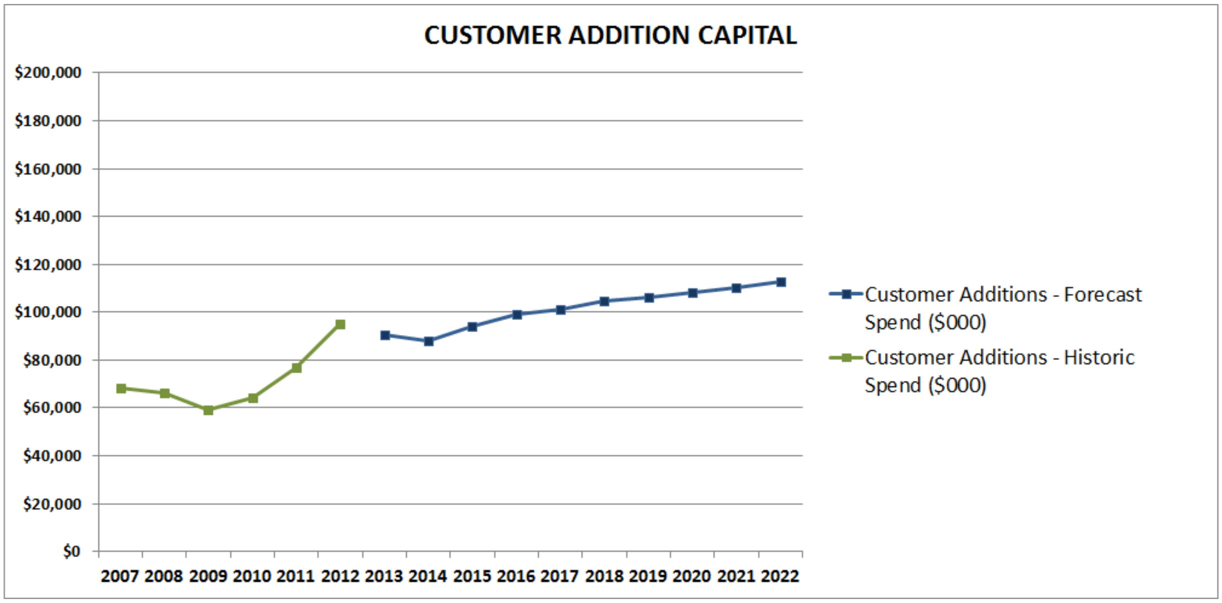


Figure 5 : Map of forecast Customer Growth by area

Implementation Plan and Estimated Capital Investments

The following chart depicts the historic capital spend on customer additions and the forecast spend for 2013-2022 based on the customer addition forecast numbers.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$68,323	$66,132	$59,257	$64,226	$77,116	$94,823	$90,652	$87,835	$94,095	$98,859	$101,015	$104,571	$105,956	$108,137	$110,324	$112,966

Chart 6 : Customer Additions Capital Forecast

While the customer additions forecast between 2017 and 2022 is expected to be relatively flat at approximately 40,000 per year, the upward trend in forecasted spend is primarily due to the application of a 2% annual inflation rate for 2014 and beyond.

5.3 Reinforcements

Introduction

Reinforcement projects are the installation of new or modification of existing gas distribution plant to maintain required system pressures. Adequate system pressures are required to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations.

The objective at EGD for network design is that the system must meet anticipated peak hourly demand at a temperature-dependent design condition depending on geography. All load additions to the system are modeled based on this design temperature as shown in the table below.

Temperature Region	Peak Temperature (Average Temperature on the peak day)	Degree Day
Peterborough and Lindsay	-28 °C	46
Georgian Bay and Barrie	-26 °C	44
Ottawa Area	-29 °C	47
Greater Toronto Area	-23 °C	41
Niagara Area	-21 °C	39

Table 3 : Regional Peak Daily Design Temperature

On an annual basis EGD completes four major functions as part of planning for reinforcements. These are load gathering, simulation, annual forecast and long range system planning, each of which is discussed below. This process allows EGD to build and validate the piping system models used for network analysis based on actual field conditions. Forecasted growth, both short and long term, are incorporated into these models to predict system performance. The two outcomes of this process are small localized reinforcements that are required for the upcoming heating season, and larger projects that are incorporated into the Company's Asset Plan.

Load Gathering

The Load Gathering process extracts actual billed customer consumption data for all accounts and matches this with locally recorded temperatures for each customer. This data gathering process provides Enbridge with a reliable, repeatable and predictable process that generates individual customer consumption. Based upon the temperature inputs and the predicted customer consumption, a load for each customer is assigned to selected points within the system models. Specific large volume customers are reviewed on an annual basis and loads are assigned based on actual consumption and contractual parameters.

Simulation

The Simulation function is performed after the current heating season by utilizing the system models with the customer consumption from the load gathering process. This combination of inputs provides the basis for the pipeline pressure and flow analysis. The resultant pressure and flow information is then compared to actual field chart or recorder readings taken during seasonally cold temperatures throughout the gas distribution system. The loads and pressure inputs of the final system models are adjusted to simulate field conditions. This verified model then becomes the piping system of record that can then be used for all subsequent piping system analysis.

Annual Forecast

Using the verified model described above, additional customer loads that are forecasted for the upcoming heating season are applied. Overall system pressures and station flows are assessed to ensure that all system minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring and in some cases small localized reinforcements will be required.

Long Range System Planning

EGD engages in long range system planning that considers a minimum of 10 years of customer growth to ensure the adequacy of system performance over the longer term.

The forecasted future customer growth is obtained from a number of different sources as described in section 5.2. Information obtained from government agencies, municipalities, consultants, and developers, is used to allocate customer growth and loads. The reliability of the system is dependent on maintaining minimum system pressures at key control locations and ensuring that stations have the necessary capacity.

Reinforcement solutions are considered if minimum system pressures cannot be maintained with forecasted loads applied. Each of the reinforcement segments identified is evaluated on a case by case basis considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, damage history, constructability, cost, environmental impacts and future expansion or development potential.

The functions described above are used to determine the need and timing of routine reinforcement projects over a 10-year period.

From this point, design alternatives are evaluated for individual reinforcement projects. As part of this evaluation, cost estimates are developed for each alternative based on typical unit costs experienced in recent projects. The most economical alternative is then included in the Asset Plan.

Requirements

Routine Reinforcements:

The following tables and maps summarize the known requirements by area as of April 2013. Areas of the map shaded red indicate expected areas of customer growth. The HP/XHP (High Pressure/Extra-High Pressure) backbone of the pipeline system is shown in brown. Reinforcements required are indicated in green.

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 10	- 4.2 km of NPS 12 HP on Bathurst St from Steeles Ave to Sheppard Ave - 3.5 km of NPS 12 HP on Sheppard Ave from Steeles Ave to Bayview Ave - Installation of a new HP to IP District Station	There is high condo growth in the Bathurst/Bayview/Steeles/Sheppard area and the station feeding this IP network is a low point in the HP system. This reinforcement will support customer growth and enhance security of supply.
	4 km of NPS 12 HP on Oriole Pkwy from Roselawn Ave to Kilbarry Rd	This reinforcement was identified as part of the Cast Iron Replacement Program to enhance security of supply in the area – the station feeding this IP network is a low point in the HP system.
	4.5 km of NPS 12 HP on Spadina Ave from MacPherson Ave to Lakeshore Blvd	This reinforcement will enhance system flexibility and provide additional security of supply for the Toronto HP system.
	3.5 km of NPS 16 HP primarily on Roxborough St from New Bayview Station (Bayview Avenue near Don Valley Pkwy) to existing NPS 24 HP main at Avenue Rd and MacPherson Ave	This reinforcement will eliminate a bottleneck that exists between the east and west feeds. It will provide better system flexibility during planed work, emergencies, and for Gas Control.
	1.2 km of NPS 12 HP on Steeles Ave from Ninth Line to Reesor Rd	This project will link the newly de-elevated NPS 16 Scarborough pipeline with the surrounding HP grid. This will create a back feed to the area for security of supply and will reinforce the area as growth continues.
	2.5 km of NPS 16 HP on Dawes Rd from Victoria Park Ave to the intersection of Woodbine Ave and Strathmore Blvd	This reinforcement will provide a secondary supply to a single Source HP System. It will support outage management.

Table 4 : Area 10 Routine Reinforcement Projects

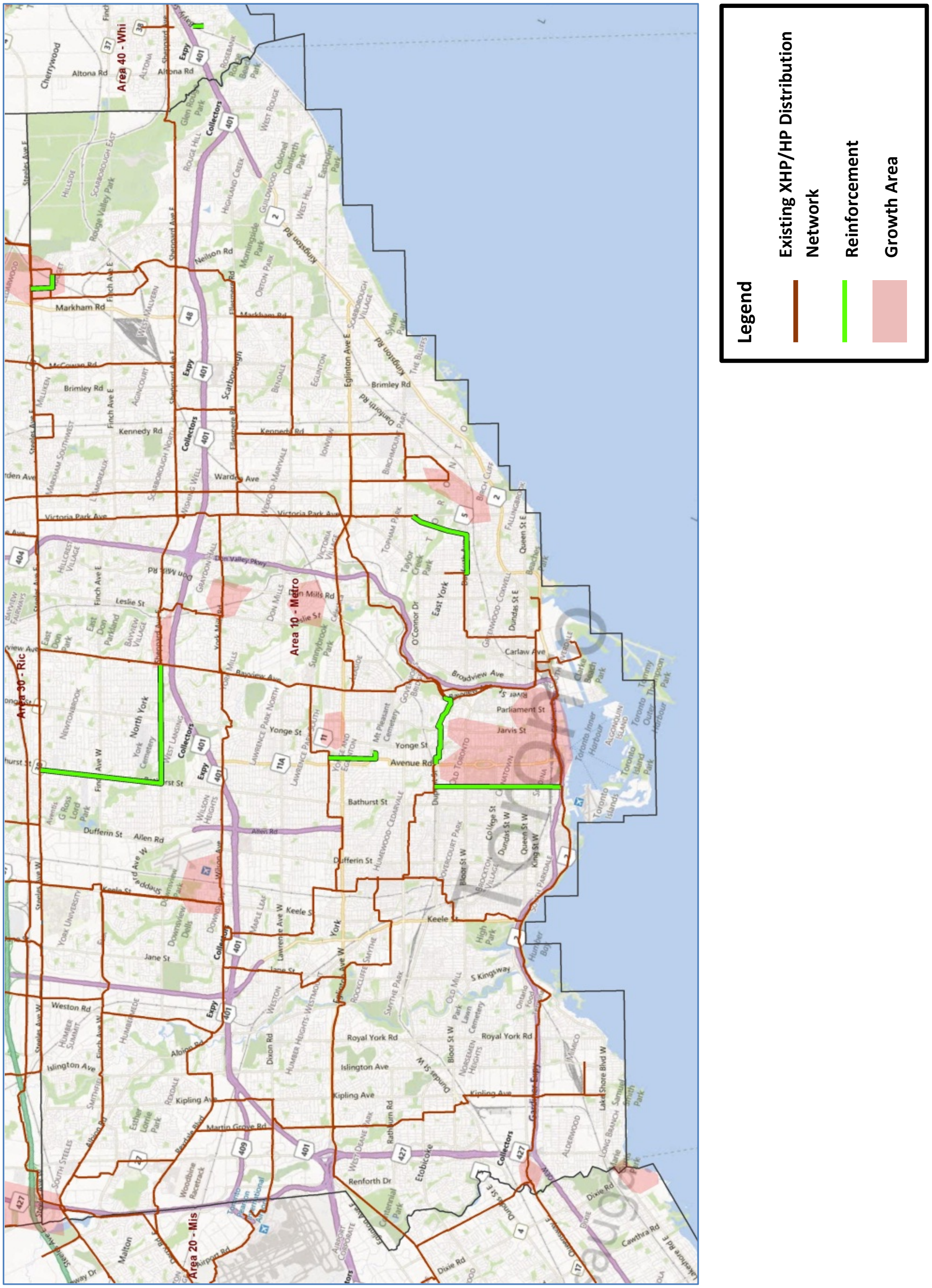


Figure 6 : Area 10 Reinforcements

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd	This reinforcement will provide additional capacity to north Brampton to support customer growth.
	1 km of NPS 6 HP on Hurontario St from Steeles Ave to County Court Blvd	This reinforcement will support industrial and commercial growth in Brampton.
	5 km of NPS 8 XHP on Hwy 10 northerly from Orangeville	This reinforcement is required to increase system capacity for organic growth in Dundalk, Shelburne, Orangeville, Erin, and Grand Valley.
	250 m of NPS 6 XHP connecting the existing NPS 4 XHP at Mississauga Rd and Bovaird Dr to the NPS 24 XHP Pine Valley line (Mississauga Rd close to CNR)	This project is to support system reliability in this area and future growth
	4.5 km of NPS 4 PE on Old Church Rd from The Gore Rd toward Humber Trail	This reinforcement will supply gas to a subdivision
	Lisgar Gate Station Rebuild	The rebuild will convert it from a gate station to a feeder station

Table 5 : Area 20 Routine Reinforcement Projects

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 50	Alliston Reinforcement Phase 2 - 1.5 km of NPS 8 XHP	This reinforcement is required to meet capacity requirements in Alliston and Everett in the next 10 years. Without this reinforcement, the system low pressure will drop below the minimum system pressure by the winter 2016/2017.
	Alliston Reinforcement Phase 3 - 2.8 km of NPS 8 XHP	This reinforcement is required to meet capacity requirements in Alliston and Everett in the next 10 years.
	Innisfil Beach Road Reinforcement – 2.5km of NPS 8 XHP on Innisfil Beach Rd from County Rd 54 to County Rd 4	This reinforcement will support customer growth in the Town of Innisfil.
	Lockhart Road Reinforcement – 2.5 km of NPS 8 XHP on Lockhart Rd from Huronia Rd to County Rd 4	This project is under construction and will support customer growth in the southern portion of the Barrie distribution network.
	Thornton Gate Pressure Elevation (to support Innisfil Beach Rd Reinforcement and Lockhart Rd Reinforcement)	This pressure elevation is required in the Barrie and Angus system where the MOP will be increased to 500 psi from 400psi. It is a part of the Angus Reinforcement project.
	Alliston Reinforcement Phase 4 - 3 km of NPS 6 XHP on Industrial Pkwy from Tottenham Rd to Adjala Tecumseth Townline	This reinforcement is required to meet capacity requirements in Alliston and Everett in the next 10 years. Without this reinforcement, the system low pressure will drop below the minimum system pressure by the winter 2020/2021.

Table 6 : Area 50 Routine Reinforcement Projects

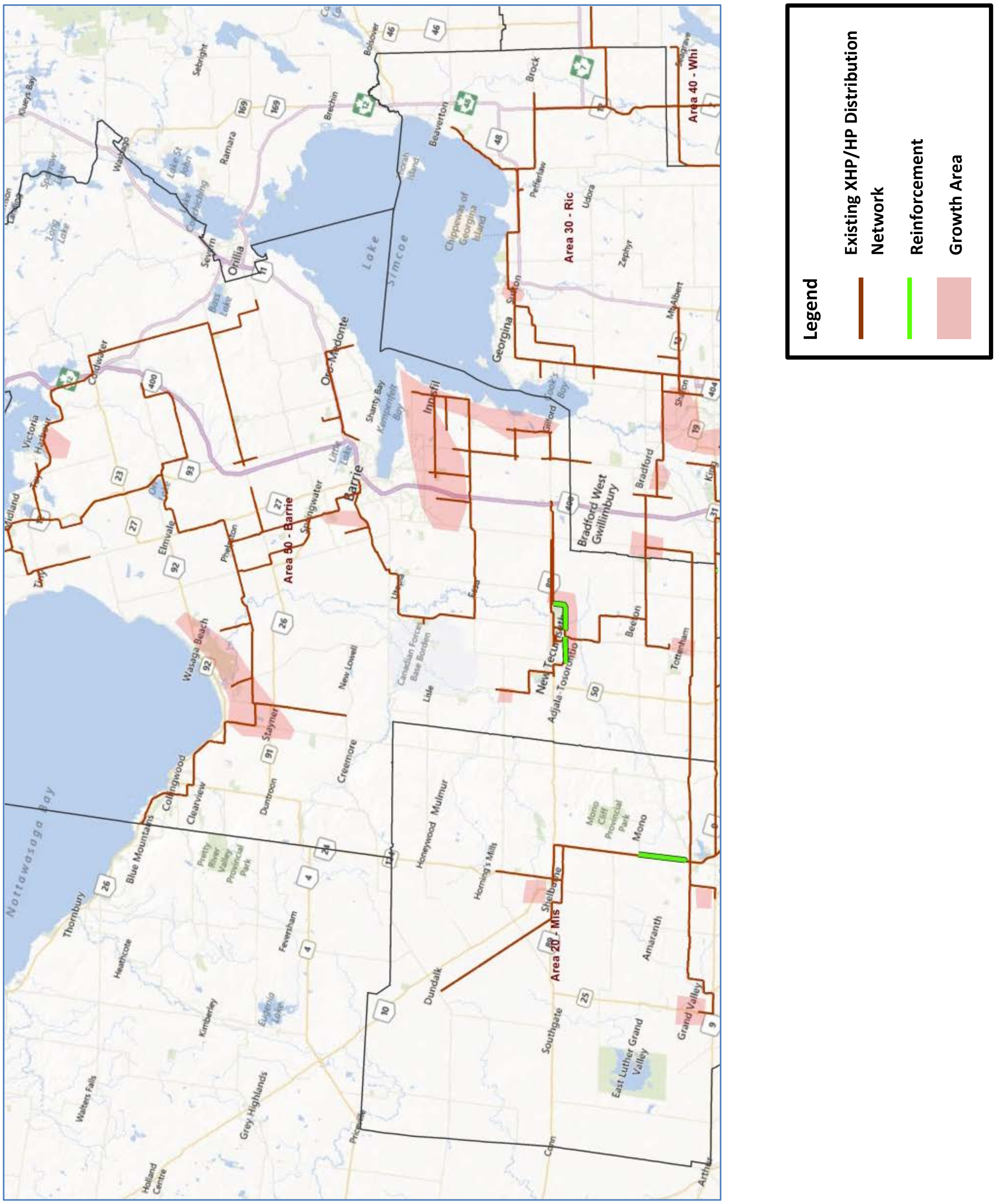


Figure 7 : Area 20 and Area 50 Reinforcements

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 30	2.5 km of NPS 8 HP on Rodinea Rd from Teston Rd to McNaughton	This project will support growth in the area.
	York Region Reinforcement Phase 1 - 6.5 km of NPS 16 XHP on Bathurst St from Bathurst Gate Station to Bloomington Rd	This reinforcement will support future growth in York Region and increase system reliability and security of supply.
	- 400 m of NPS 4 XHP on Hwy 27 from Hwy 9 to Proctor Rd - Installation of a new XHP to HP station in Schomberg	This reinforcement is required to increase system pressures in the area.
	1 km of NPS 4 XHP on 6th Concession from Silver Spring Cres to Old Stouffville Sideroad	This project will support customer growth in the area and is required to maintain system minimum pressures.
	600 m of NPS 8 HP on 16th Ave from Granton Dr to Spadina Rd	This reinforcement will support customer growth in the area and is required to maintain system minimum pressures.
	1.2 km of NPS 8 HP on Hwy 7 from Roddick Rd to Woodbine Ave	This reinforcement will support customer growth in the area and is required to maintain system minimum pressures.
	2.2 km of NPS 8 XHP on 19th Ave from 9th Line to Reesor Rd	This reinforcement is required to maintain system minimum pressures. The Markham outlet feed supports the Stouffville/Uxbridge system.
	York Region Reinforcement Phase 2 - 8.4 km of NPS 12 XHP on Bathurst St from Bloomington Rd to Mulock Dr	This reinforcement is required to support future growth in York Region. It will also increase system reliability and security of supply.

Table 7 : Area 30 Routine Reinforcement Projects

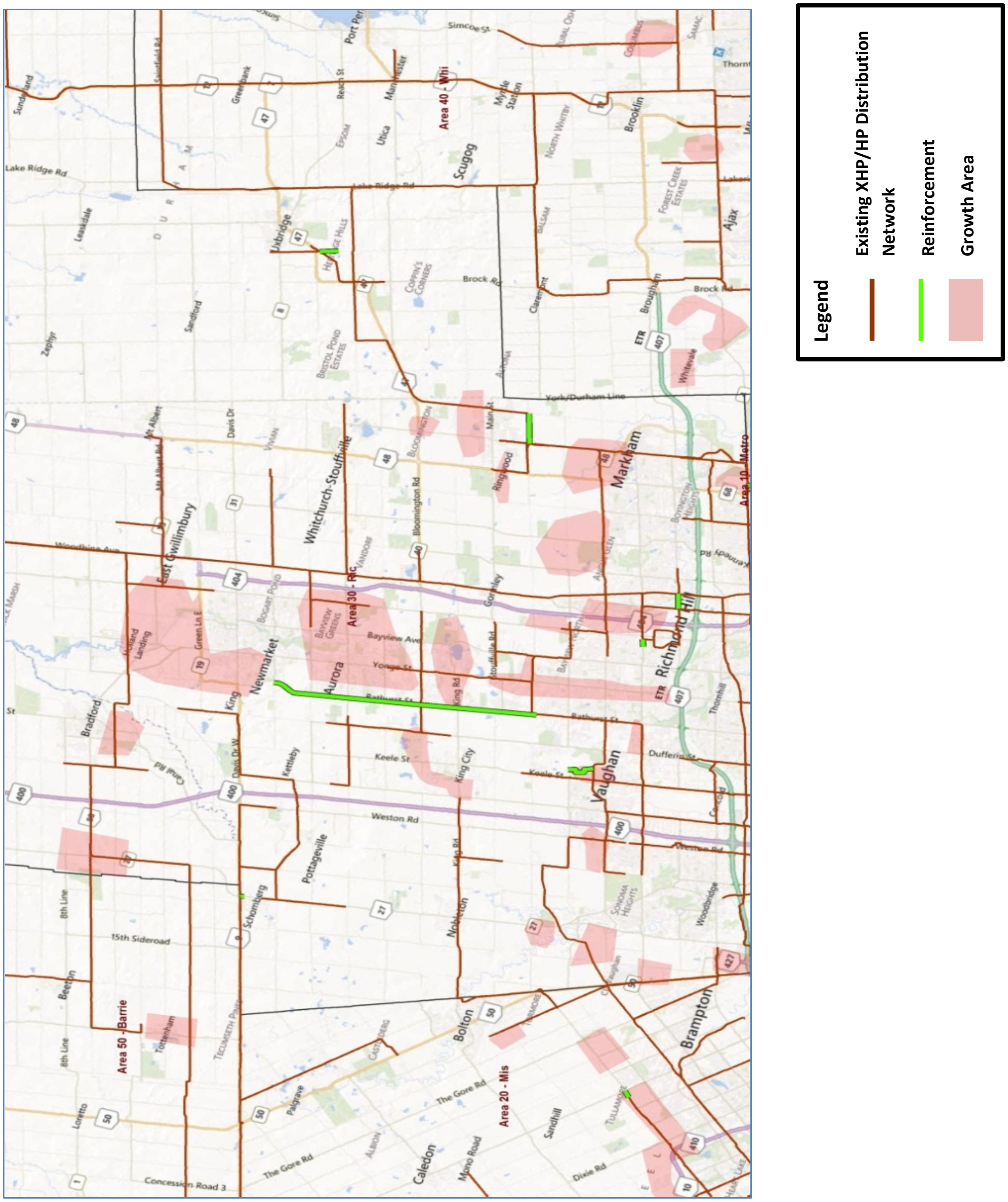


Figure 8 : Area 30 Reinforcements

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 40	Peterborough Reinforcement Phase 2 - 2.4 km of NPS 8 XHP on Preston Rd from Lansdowne St W north to Mount Pleasant Rd	This reinforcement is required to maintain system capacity with the addition of approved subdivisions in North Peterborough and Lakefield.
	Peterborough Reinforcement Phase 3 - 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant Rd to Lily Lake Rd	This reinforcement is required to maintain system capacity with future growth in Peterborough, Bridgenorth and Lakefield.
	- Kingston Road Reinforcement - 2.4 km of NPS 6 XHP on Kingston Rd from Lakeridge Rd to Salem Rd - Installation of a new station	This reinforcement is required for additional capacity – the existing main is at capacity and the new pipeline will improve system pressures and support future growth in the area.
	- 3km of NPS 6 HP on Solina Rd from Bloor St to Baseline Rd + Baseline Rd from Solina Rd to Osborne Rd + Osborne Rd from Baseline Rd to DYEC - 500 m of NPS 8 HP 401 crossing - 2km of NPS 8 HP on Regional Rd 57 from Concession Rd 4 to Gaud Gate	This reinforcement will supply the Durham/York Energy Center.
	300 m of NPS 4 HP on Whites Rd from Hwy 401 to Oklahoma Dr	This reinforcement will improve system capacity in south Pickering.
	Replace 1.8 km of NPS 12 XHP with 1.8 km of NPS 16 XHP from Oshawa Gate Station to the intersection of Conlin Rd and Wilson Rd	This reinforcement is required for overall system growth in Pickering and Oshawa.
	- 2.5km of NPS 8 XHP on HWY 35/7 from existing NPS 8 XHP on Hwy 35 to Angeline St. - Installation of a District Station from existing NPS 8 XHP main to existing NPS 4" PE IP main at Northeast corner Angeline St & Hwy 35/7	This reinforcement is required to support subdivision growth in Lindsay system and will allow future community expansion.
	2.8 km of NPS 8 HP connecting existing NPS 8 HP at Brock Rd and Kingston Rd to existing NPS 6 HP at Westney Rd and Kingston Rd	This reinforcement will support future growth and improve system capacity.

Table 8 : Area 40 Routine Reinforcement Projects

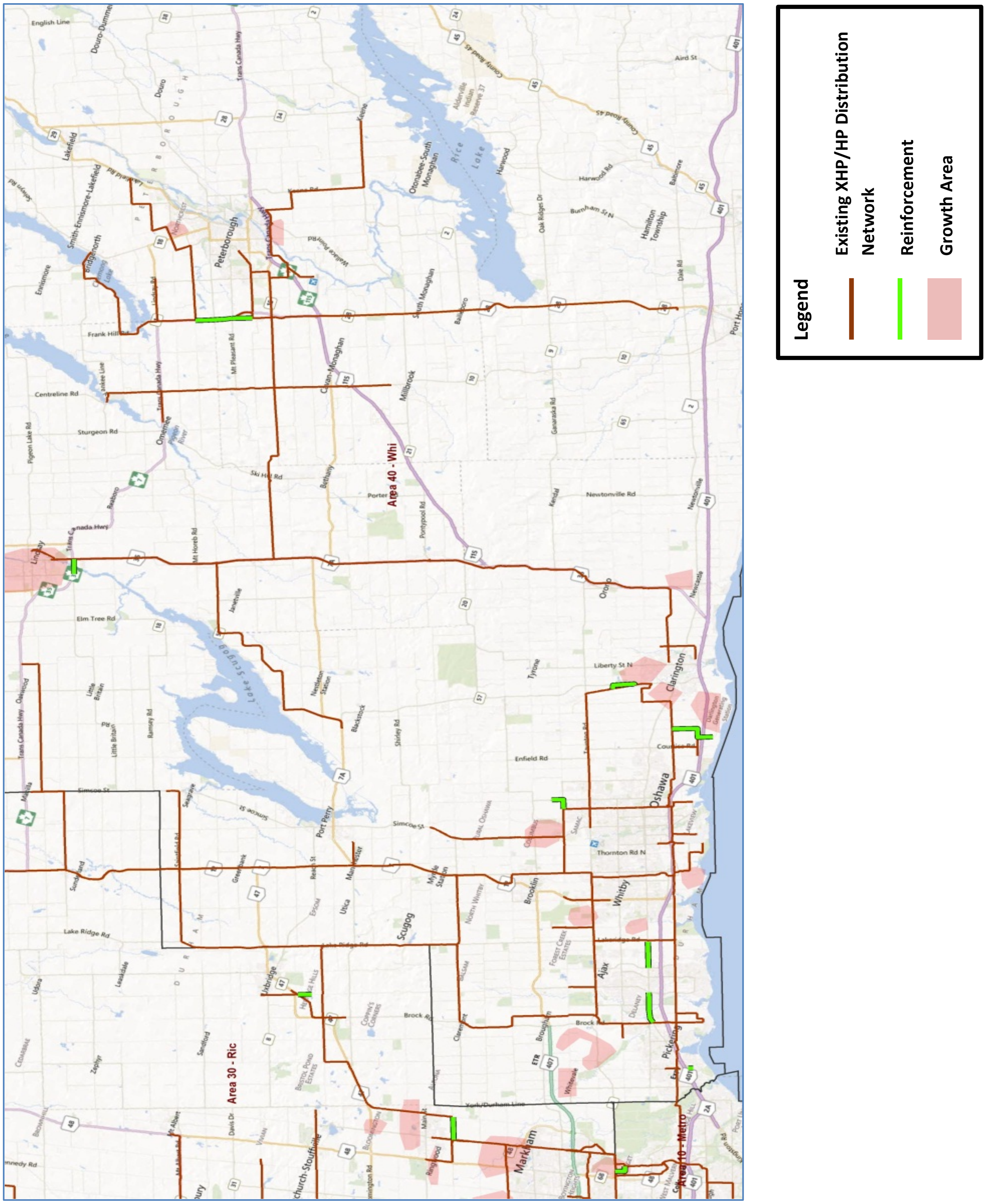


Figure 9 : Area 40 Reinforcements

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 60	Strandherd Dr Reinforcement - 1 km of NPS 8 XHP crossing Rideau St at Woodroofe Ave and Hwy 16 toward River Rd	This reinforcement supports continued customer growth in Southern Ottawa.
	Ottawa Innes Road Replacement - Replace 3 km of NPS 8 XHP with NPS 12 XHP	This is an Integrity project to replace a section of main running at greater than 30% SMYS. It will remove an existing system bottleneck while ensuring that a mandated inspection or elimination of this high stress pipeline is completed by December 2013.
	Richmond Pressure Elevation - 5.3 km of NPS 4 HP	This pressure elevation will accommodate increasing gas demand due to customer growth.
	6.7 km of NPS 20 XHP on Hunt Club Rd from Greenbank Rd to Prince of Wales Dr	This reinforcement is Phase II of the Ottawa Reinforcement. It is required to support customer growth and to manage flow at Ottawa Gate Station.
	Woodroffe Upgrades – Intersection of Fallowfield Rd and Woodroffe Rd – replacement of 15m of NPS 4 to NPS 8 XHP	This project removes a bottleneck from the existing NPS 8 distribution system to support continued growth in South Ottawa as related to the Strandherd Dr Reinforcement.

Table 9 : Area 60 Routine Reinforcement Projects

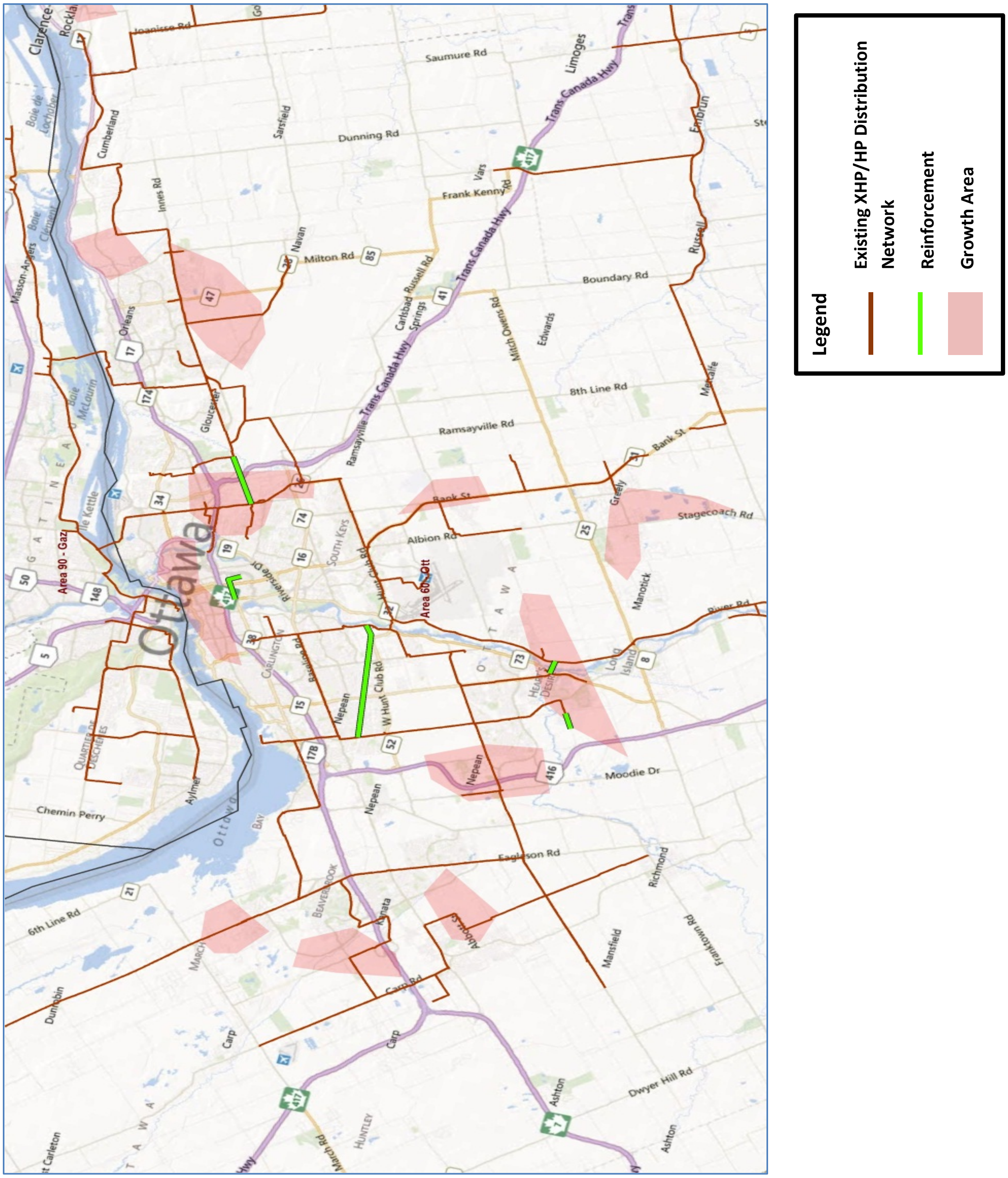


Figure 10 : Area 60 Reinforcements

AREA	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
Area 80	Chippawa Creek Road Reinforcement - Replace 400 m of NPS 6 HP with NPS 12 HP	This project supports customer growth.

Table 10 : Area 80 Routine Reinforcement Projects

Major Reinforcements:

In addition to the routine reinforcements above, from time to time major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system are required to further support customer growth and address system reliability and security of supply issues. These reinforcements are characterized by their size and complexity, and do not arise as frequently as routine reinforcements.

As of April 2013, two such major reinforcement projects have been identified – the GTA project, and the Ottawa Reinforcement project.

Leave to construct applications have been filed for both these projects.

The following is a summary of these major reinforcements.

PROJECT	PROJECT DESCRIPTION	ADDITIONAL PROJECT DETAILS
GTA Project	- 20.9 km of NPS 42 XHP along the 407 corridor from the Bram West Interconnect to Albion Rd Station near Hwy 427 and Albion Rd - 23 km of NPS 36 XHP along the 407 and existing hydro corridors from Keele St and Steeles Ave to Sheppard Ave and Pharmacy Ave	This project will upgrade the XHP grid system in the Greater Toronto Area to meet load growth, ensure continued reliability, and enable access to lower cost natural gas supplies.
Ottawa Reinforcement	19.3 km of NPS 24 XHP from Richmond Gate Station to Greenbank Rd	This project supports customer growth and enhances security of supply. It also alleviates capacity restrictions at Ottawa Gate Station.
	Ottawa Reinforcement additional construction costs	

Table 11 : Major Reinforcements

Implementation Plan and Estimated Capital Investments

Based on the reinforcement requirements, an implementation schedule was developed for reinforcement projects over the term of the Asset Plan. The schedule of projects was based on the need to maintain minimum system pressures over the term of the Asset Plan and taking into account the time required to design and construct the required new assets. An estimate was also developed for the capital required for each of the projects.

The following is a summary of this schedule.

Routine Reinforcements:

AREA	PROJECT DESCRIPTION	Dates	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013-2022) ($000)
Area 10	- 4.2 km of NPS 12 HP on Bathurst St from Steeles Ave to Sheppard Ave - 3.5 km of NPS 12 HP on Sheppard Ave from Steeles Ave to Bayview Ave - Installation of a new HP to IP District Station	2018						A-10					$9,937
	4 km of NPS 12 HP on Oriole Pkwy from Roselawn Ave to Kilbarry Rd	2018						A-10					$6,624
	4.5 km of NPS 12 HP on Spadina Ave from MacPherson Ave to Lakeshore Blvd	2019							A-10				$7,883
	3.5 km of NPS 16 HP primarily on Roxborough St from New Bayview Station (Bayview Avenue near Don Valley Pkwy) to existing NPS 24 HP main at Avenue Rd and MacPherson Ave	2017					A-10						$21,649
	1.2 km of NPS 12 HP on Steeles Ave from Ninth Line to Reesor Rd	2014		A-30									$1,530
	2.5 km of NPS 16 HP on Dawes Rd from Victoria Park Ave to the intersection of Woodbine Ave and Strathmore Blvd	2019							A-10				$5,631
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd	2013	A-20										$1,000
	1 km of NPS 6 HP on Hurontario St from Steeles Ave to County Court Blvd	2015			A-20								$780
	5 km of NPS 8 XHP on Hwy 10 northerly from Orangeville	2013	A-20										$1,900
	250 m of NPS 6 XHP connecting the existing NPS 4 XHP at Mississauga Rd and Bovaird Dr to the NPS 24 XHP Pine Valley line (Mississauga Rd close to CNR)	2020								A-20			$287
	4.5 km of NPS 4 PE on Old Church Rd from The Gore Rd toward Humber Trail	2013	A-20										$650
	Lisgar Gate Station Rebuild	2019							A-20				$3,378

AREA	PROJECT DESCRIPTION	Dates	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013-2022) ($000)
Area 30	2.5 km of NPS 8 HP on Rodinea Rd from Teston Rd to McNaughton	2013	A-30										$520
	York Region Reinforcement Phase 1 - 6.5 km of NPS 16 XHP on Bathurst St from Bathurst Gate Station to Bloomington Rd	2014-2015		A-30	A-30								$10,914
	- 400 m of NPS 4 XHP on Hwy 27 from Hwy 9 to Proctor Rd - Installation of a new XHP to HP station in Schomberg	2013	A-30										$500
	1 km of NPS 4 XHP on 6th Concession from Silver Spring Cres to Old Stouffville Sideroad	2017				A-30							$433
	600 m of NPS 8 HP on 16th Ave from Granton Dr to Spadina Rd	2018						A-30					$662
	1.2 km of NPS 8 HP on Hwy 7 from Roddick Rd to Woodbine Ave	2018						A-30					$883
	2.2 km of NPS 8 XHP on 19th Ave from 9th Line to Reesor Rd	2018						A-30					$1,767
	York Region Reinforcement Phase 2 - 8.4 km of NPS 12 XHP on Bathurst St from Bloomington Rd to Mulock Dr	2019							A-30				$14,190
Area 40	Peterborough Reinforcement Phase 2 - 2.4 km of NPS 8 XHP on Preston Rd from Lansdowne St W north to Mount Pleasant Rd	2014		A-40									$1,530
	Peterborough Reinforcement Phase 3 - 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant Rd to Lily Lake Rd	2017					A-40						$1,299
	- Kingston Road Reinforcement - 2.4 km of NPS 6 XHP on Kingston Rd from Lakeridge Rd to Salem Rd - Installation of a new station	2014		A-40									$918
	- 3km of NPS 6 HP on Solina Rd from Bloor St to Baseline Rd + Baseline Rd from Solina Rd to Osborne Rd + Osborne Rd from Baseline Rd to DYEC - 500 m of NPS 8 HP 401 crossing - 2km of NPS 8 HP on Regional Rd 57 from Concession Rd 4 to Gaud Gate	2013	A-40										$500
	300 m of NPS 4 HP on Whites Rd from Hwy 401 to Oklahoma Dr	2015			A-40								$208
	Replace 1.8 km of NPS 12 XHP with 1.8 km of NPS 16 XHP from Oshawa Gate Station to the intersection of Conlin Rd and Wilson Rd	2016				A-40							$3,714
	- 2.5km of NPS 8 XHP on HWY 35/7 from existing NPS 8 XHP on Hwy 35 to Angeline St. - Installation of a District Station from existing NPS 8 XHP main to existing NPS 4" PE IP main at Northeast corner Angeline St & Hwy 35/7	2015			A-40								$1,665
	2.8 km of NPS 8 HP connecting existing NPS 8 HP at Brock Rd and Kingston Rd to existing NPS 6 HP at Westney Rd and Kingston Rd	2017					A-40						$2,706

AREA	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013-2022) ($000)
Area 50	Alliston Reinforcement Phase 2 - 1.5 km of NPS 8 XHP	2015				A-50								$1,040
	Alliston Reinforcement Phase 3 - 2.8 km of NPS 8 XHP	2016					A-50							$2,111
	Innisfil Beach Road Reinforcement – 2.5km of NPS 8 XHP on Innisfil Beach Rd from County Rd 54 to County Rd 4	2013		A-50										$1,200
	Lockhart Road Reinforcement – 2.5 km of NPS 8 XHP on Lockhart Rd from Huronia Rd to County Rd 4	2013		A-50										$800
	Thornton Gate Pressure Elevation (to support Innisfil Beach Rd Reinforcement and Lockhart Rd Reinforcement)	2014			A-50									$765
	Alliston Reinforcement Phase 4 - 3 km of NPS 6 XHP on Industrial Pkwy from Tottenham Rd to Adjala Tecumseth Townline	2019								A-50				$2,159
Area 60	Strandherd Dr Reinforcement - 1 km of NPS 8 XHP crossing Rideau St at Woodroofe Ave and Hwy 16 toward River Rd	2013		A-60										$1,900
	Ottawa Innes Road Replacement - Replace 3 km of NPS 8 XHP with NPS 12 XHP	2013		A-60										$5,810
	Richmond Pressure Elevation - 5.3 km of NPS 4 HP	2014			A-60									$1,020
	6.7 km of NPS 20 XHP on Hunt Club Rd from Greenbank Rd to Prince of Wales Dr	2018							A-60					$17,776
	Woodroffe Upgrades – Intersection of Fallowfield Rd and Woodroffe Rd – replacement of 15m of NPS 4 to NPS 8 XHP	2013		A-60										$80
Area 80	Chippawa Creek Road Reinforcement - Replace 400 m of NPS 6 HP with NPS 12 HP	2014			A-80									$408
Localized Annual Reinforcements	Relatively small localized reinforcements identified as part of the Annual Forecast to ensure system reliability for the next heating season	2013-2022												$20,327

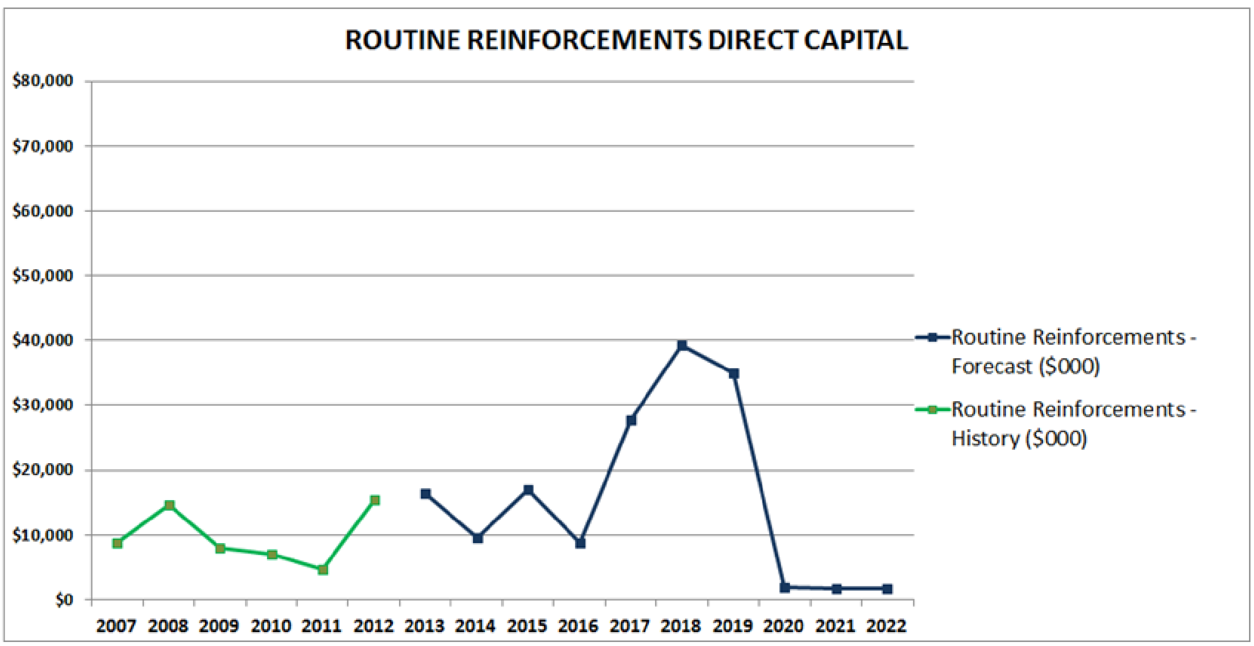
Figure 11 : Routine Reinforcements – Timing and Distribution of Capital Spend

Major Reinforcements:

PROJECT	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013-2022) ($000)
GTA Project	- 20.9 km of NPS 42 XHP along the 407 corridor from the Bram West Interconnect to Albion Rd Station near Hwy 427 and Albion Rd - 23 km of NPS 36 XHP along the 407 and existing hydro corridors from Keele St and Steeles Ave to Sheppard Ave and Pharmacy Ave	2011-2015			A-10									$620,439
Ottawa Reinforcement	19.3 km of NPS 24 XHP from Richmond Gate Station to Greenbank Rd	2013		A-60										$43,600
	Ottawa Reinforcement additional construction costs	2014			A-60									$5,100

Figure 12 : Major Reinforcements – Timing and Distribution of Capital Spend

The chart below depicts the historic and forecast capital spend for routine reinforcements

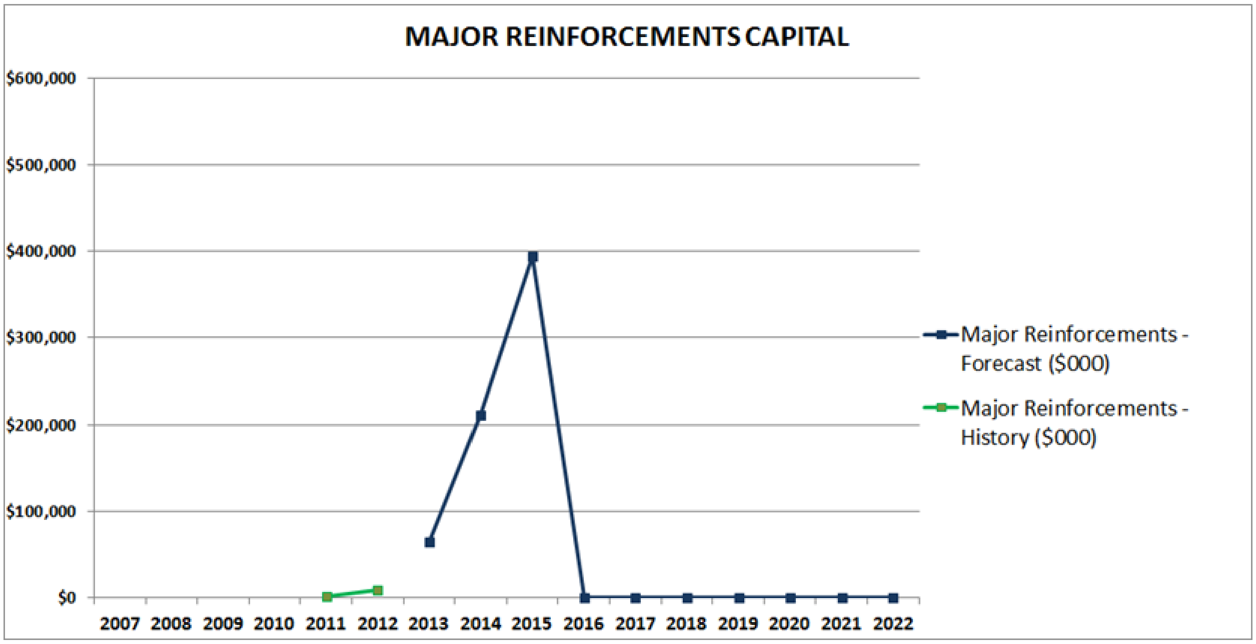


2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$8,795	$14,710	$8,061	$7,054	$4,742	$15,468	$16,360	$9,486	$16,959	$8,743	$27,710	$39,305	$34,930	$2,010	$1,757	$1,793

Chart 7 : Capital Spend for Routine Reinforcements

Based on information available at this point in time, long range system planning does not identify the need for any specific reinforcements in the period of 2020 to 2022. Hence, the capital forecast for this period is based only on the need for localized reinforcements that are identified through the annual forecasting process.

The following chart depicts the same information for Major Reinforcements



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$0	$0	$0	$0	$1,476	$8,738	$64,717	$210,370	$394,052	$0	$0	$0	$0	$0	$0	$0

Chart 8 : Capital Spend for Major Reinforcements

5.4 System Integrity and Reliability

Introduction

System Integrity and Reliability captures a category of spending focused on:

- Maintaining the natural gas distribution pressurized system at or above adopted standards for safety and operational effectiveness (System Integrity)
- Ensuring the dependable delivery of natural gas to EGD's customers and end-users (Reliability)

A critical responsibility in managing a natural gas distribution system is to understand potential threats to the safety and reliability of the system. Threats to the system can manifest risks defined as a combination of likelihood and impact, which if not appropriately managed, can lead to serious incidents.

In general, risks associated with gas distribution assets occur when there is a loss of containment of gas from the system, when the system is operating above or below the intended design pressure range, or there is a loss of supply of gas to any portion of the system. Two basic characteristics of natural gas are that it is lighter than air and when it is released from containment, it will follow the path of least resistance. In most cases, a release of gas will result in the gas escaping to the atmosphere with minor consequences. However, if the gas ignites or if the release of gas follows a path of least resistance to a confined space, increasing the probability of ignition, significant serious consequences can result. There are several threats to a gas distribution system, such as third party damages, corrosion or degradation, equipment malfunction, etc.

Threats to the gas distribution system have existed from the inception of the industry. EGD has practiced a form of asset management to address integrity issues throughout its history. These integrity management practices have focused on a wide variety of mitigation programs, including ongoing leak detection and damage prevention programs supported by effective emergency response processes to reactively respond to leaks and damages. In some cases, integrity management practices have been directed at proactively addressing specific assets that posed significant risks such as cast iron or bare steel mains. The Company interprets recent changes to regulation to now require more proactive identification and mitigation of risk (See Legislation below).

EGD has been evolving its Integrity Management process towards a more rigorous, risk-based decision making approach within the context of a comprehensive Asset Management System. Several drivers, including industry trends and developments, legislation, advancements in gas pipeline inspection technology, and the evolution of EGD's Asset Management discipline are contributing to EGD's evolving Integrity Management process.

Industry Trends and Developments

Major pipeline incidents in recent years have led to heightened awareness and concern regarding the integrity and reliability of natural gas transmission and distribution systems across North America. One such event was the September 2010 San Bruno pipeline rupture and ignition in California. The event resulted in the death of eight individuals, the destruction of 38 homes, and injury to several additional individuals and damage to several other properties in the area. In the wake of the event, Jacob's Consultancy was hired by the California Public Utilities Commission to conduct an independent review and make recommendations to improve the safety of the California natural gas transmission system. One comment in the report was,

> "Worker Safety versus System Safety – Management's focus in recent times appears to have been on the occupational safety of its employees and lacking an equivalent focus on the public safety aspects of its system. …there is the lack of management focus on how system integrity would be managed and assured…"[1]

Further, the National Transportation Safety Board (NTSB) report on the same event stated that the probable cause for the event was:

> "(1) inadequate quality assurance and quality control in 1956 during [Pacific Gas & Electric's] …relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase…; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section."[2]

[1] Report of the Independent Review Panel San Bruno Explosion, Jacob's Consultancy, June 8, 2011, p.15.

[2] Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010, National Transportation Safety Board Accident Report NTSB/PAR-11/01 PB2011-916501, 2011, p. xii.

Another example of such an event was Enbridge Inc.'s event in Marshall, Michigan. The NTSB made the following comment in its report on this event:

> "Because of the improvements to safety that accrue from the use of a comprehensive [Safety Management System] SMS, the NTSB recommends that [American Petroleum Institute] API facilitate the development of an SMS standard specific to the pipeline industry that is similar in scope to the API's [Recommended Practice] RP 750, *Management of Process Hazards*."[3]

EGD and the industry have increased focus on system integrity and reliability in a number of ways. San Bruno highlighted the need for new standards for asset and work records focused on ensuring that records that are vital to the safe and reliable operation of transmission and distribution systems are verifiable, traceable and complete, as was advised by the Pipeline and Hazardous Materials Safety Administration (PHMSA).[4] This has then led to the Company's review and verification of the Maximum Operating Pressure (MOP) of high stress pipelines.

Further, increased efforts are being made to better understand the condition of plant assets through activities such as in-line inspection, engineering analysis and risk assessments for both the transmission and distribution systems. Proactive programs are being implemented to further mitigate those risks.

Legislation

EGD designs and operates its natural gas pipeline system in accordance with Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), in addition to all other applicable codes, standards and regulations. This regulation adopts the Canadian Standards Association code CSA Z662-11 Oil and Gas Pipeline Systems with amendments as defined in Section 2 of Ontario's Technical Standards and Safety Authority (TSSA) Code Adoption Document (CAD) amendment, FS-196-12, dated November 1, 2012.

The most significant change from the 2007 to the 2011 version of the CSA Z662, and the corresponding 2008 and 2012 TSSA CAD was the requirement to consider Annex N versus the

[3] Ibid, p.132.

[4] PHMSA Advisory Bulletin ADB-11-01, Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.

now obsolete Annex M for pipelines operating below 30% SMYS. Prior to the CSA Z662-11 edition, Annex N only applied to pipelines operating at or over 30% SMYS. Annex N is written in mandatory language to facilitate adoption where regulatory authorities wish to adopt it formally. EGD has been using Annex N as a guideline for its high stress pipeline integrity management program since it first appeared in the CSA Z662 standard.

The 2008 CAD outlined the requirement to consider Annex M for pipeline systems operating at less than 30% SMYS. The language in Annex M was intentionally less stringent to allow time for distribution companies to develop their Distribution System Integrity Management Programs (DSIMP). The use of the word "should" throughout Annex M allowed distribution companies to focus on areas of Annex M they felt were important.

Similar to how EGD worked prior to 2008, from 2008 to 2012 EGD focused on the following in order to determine other areas or assets that should be considered for remediation:

- Maintaining existing programs that were already implemented such as Cast Iron, Bare Steel, etc. replacement programs
- Analyzing leak, damage and incident reports
- Conducting subject matter advisor interviews
- Commencing studies to analyze emerging risks

In 2012 with the new TSSA CAD adopting CSA Z662-11, the old Annex M was removed from the standard and replaced by Annex N, which is to apply to all assets (both above and below 30% SMYS). Therefore, the wording that applies to DSIMP changed from "should" to "shall". Though EGD has always conducted a form of Integrity Management, EGD's Integrity Management process is now required by code to analyze the entire distribution system and its components, determine their suitability for continued service and remediate assets determined by the Company to have a risk of failure. Where studies have concluded that the risk is not acceptable, mitigation must be implemented. Where the studies are not conclusive, they must continue until the risk level is better understood, such that effective mitigation can be implemented, evaluated and continuously improved. Therefore, EGD will continue to assess potential failures to its operating assets, and define and implement prudent projects and programs to address these risks.

The following figure depicts the requirements of Annex N. To comply with this regulation, EGD must plan, assess, act, measure and improve its management of integrity on a continuous improvement cycle and in a proactive manner.

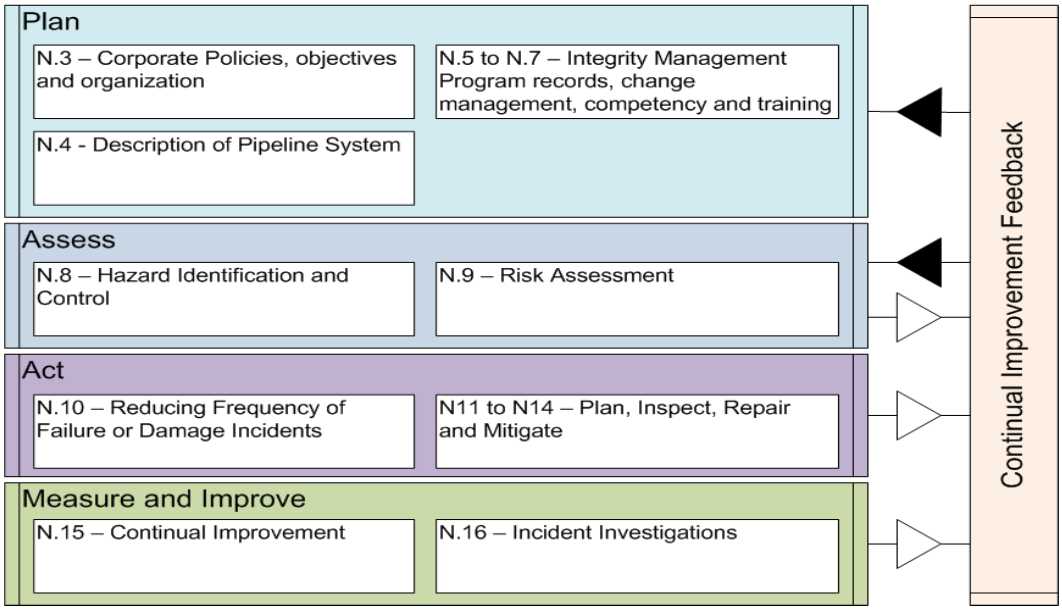


Figure 13 : Elements of CSA Z662 Annex N

A critical aspect of such a program is the ability to proactively anticipate conditions that can lead to potential failures and to mitigate or eliminate this potential before an incident occurs. This requirement is included in section 3.2 of CSA Z662-11, Pipeline System Integrity Management Program as follows:

> "Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clauses 10.3 and 10.5) for managing the integrity of the pipeline system so that it is suitable for continued service, including procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data. Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for
>
> (a) assessing current potential risks;
> (b) identifying risk reduction approaches and corrective actions;
> (c) implementing the integrity management program; and
> (d) monitoring results"

In addition to studying actual failures to determine appropriate future mitigation, EGD must also assess potential failures to its operating assets and define and implement prudent projects and programs to mitigate these risks.

For further detail about the legislative requirements that apply to Enbridge's System Integrity and Reliability projects, please refer to the Appendix section of this document, which outlines the specific legislative provisions which dictate, or are applicable to, each of the programs and projects contemplated in the System Integrity and Reliability section of this Asset Plan.

EGD's Current Integrity Management Process

Influenced by the above drivers, EGD is continuing to work to refine its risk based decision making approach to Integrity Management. This is consistent with the evolution of regulations from a traditional "prescriptive" approach to an "outcomes based" or "risk based" approach. Annex N of CSA Z662 is an example of regulation that is evolving in this direction.

A risk based approach can be defined as a comprehensive and defensible process to identify threats, assess the potential risks from those threats, prioritize these risks and specify appropriate asset investments to mitigate likelihoods and impacts to prudently manage the risks.

Following this risk-based approach, EGD has been striving to better understand threats and related risks to the distribution system. One area of focus has been working to gain a better understanding of the condition of different classes of assets that comprise the system, based on factors such as the age profile of the assets. As assets age, failure rates are anticipated to increase with the failure profile becoming more acute as the assets approach the end of their useful life. This increasing failure profile is expected to drive an increasing spend profile to maintain and ultimately replace the assets.

EGD has also been striving to improve the condition monitoring of its assets to better understand the factors that contribute to failure rates. For the past five years, since Distribution System Integrity Management Programs (DSIMP) have been required to be considered through the CSA standard and the TSSA, EGD has been working to comprehensively and proactively analyze asset condition and assess which threats contribute to higher failure rates.

In the past, this form of analysis has at times been limited by the availability and completeness of the required asset information, which occurs throughout the industry. EGD continues to seek to improve its capture of asset information, which in turn continues to yield improved understanding of the condition and risks associated with the assets.

These analytical approaches are expected to play an increasing role in EGD’s Integrity Management process, particularly as improvements are made in gathering and correlating the required asset information. However, it is also expected that the tacit knowledge of experienced personnel will remain an important component in understanding and assessing threats and risks, prioritizing these risks and defining the mitigations needed to effectively manage these risks. Industry developments and trends will also continue to play an important role.

In this second iteration of EGD's Asset Plan, particular attention has been paid to significantly enhancing the risk identification and assessment methodology. A detailed description of this enhanced methodology is included in the Requirements section below.

In summary, this evolving Integrity Management process is intended to help ensure that EGD can continue to constantly work to eliminate potential failures in a prudent manner over time, in compliance with current and future anticipated regulations. This complies with the Company’s obligations as a gas distributor.

Requirements

In applying the above Integrity Management approach, the process EGD undertook to develop the system integrity and reliability requirements of the Asset Plan is outlined below.

As a starting point, a set of focus groups was created to identify and evaluate the risks as follows:

- Group 1: Mains, Services, Valves, and Fittings
- Group 2: Measurement and Regulation (M&R) Equipment
- Group 3: Reliability of Supply
- Group 4: Records Integrity
- Group 5: Customer Service

These focus groups collectively spanned multiple areas of expertise within the Company including Operations, Engineering, Planning, Integrity Management, and the Laboratory, from frontline to management staff.

For each of these groups, the following approach was consistently used:

Figure 14 : Approach to Addressing Risk

Identification of Risks

Given industry trends, developments, and evolving legislation as described in the introduction to this section, EGD undertook a more comprehensive approach to risk identification as compared to the last iteration of the Asset Plan. This included a greater number of facilitated consultations with subject matter advisors (SMAs), each of which was more focused on specific classes of assets or issues. Through these consultations, the SMA's identified risks, based on their recent experience, industry knowledge and their knowledge of historical EGD events.

The risks identified in the first iteration of the Asset Plan were used as the starting point for this year's process. As well, data available from EGD's operating systems, tacit knowledge interviews and existing asset condition monitoring programs were utilized to help inform this enhanced process of identifying risks.

Through this process, a total of 59 risks were identified compared with 35 risks from last year's Asset Plan. Factors that contribute to these risks were then discussed to better understand why these risks are occurring. These contributing factors were categorized into systemic (part of the system that the asset resides in and is generally found in a majority of EGD's assets) or asset specific (specific to the particular asset).

The assets, risks and associated contributing factors were all gathered and tabulated into the Risk Register described below.

The Risk Register

The following table summarizes the results of the risk identification process.

Asset Class / Issue Category	Asset / Issue	Risk Description
Mains	Carrier Pipe in Casings	Corrosion may occur on carrier pipes housed in casings, when the pipes are in contact. This contact may compromise the cathodic protection and resulting in accelerated corrosion of these pipes.
	Don River Bridge Crossing	The XHP 30" main on the Don River Bridge is in the 100 year flood plain which may lead to pipe damage causing loss of containment and customer outages.
	Field Applied Coatings on Tie-In to Steel	Field applied coatings are susceptible to corrosion where the coating is damaged or where the coating has disbonded from the pipes.
	High Stress Steel Mains	Features on steel mains due to damage, corrosion and manufacturing defects may compromise the Integrity of the pipeline.
	Isolated Steel Mains	Isolated steel mains are susceptible to accelerated corrosion due to a lack of cathodic protection.
	Older Coated Steel	Older coated steel mains are susceptible to corrosion where the coating is damaged.
	Pipelines in AC Susceptible Areas	Pipelines that are in AC corridors may be susceptible to AC corrosion.
	Plastic Mains	Failure to follow safe excavation practices leads to damages (failure to request a locate, provide a locate, provide a correct locate, dig safely).
	Segment of the 20-inch Lakeshore Line	A segment of the 20-inch Lakeshore Line has coating disbondment issues due to contaminated soil conditions. This disbondment may lead to accelerated corrosion of the pipe.
	Vintage Steel Network	Vintage Steel pipelines have the potential to exhibit integrity concerns related to suspect fittings that may not meet today's standards.
	Vintage Plastic Mains - Pre 1982	Certain vintage plastic mains have been identified in the industry to be susceptible to brittle like cracking. Cracking may result in a loss of containment.

Asset Class / Issue Category	Asset / Issue	Risk Description
Services	Bare Steel Services (LP/IP)	Bare steel services are susceptible to accelerated corrosion due to the lack of coating.
	Copper Services	Copper services may leak due to corrosion.
	Isolated Steel Services	Isolated steel services are susceptible to corrosion due to lack of cathodic protection.
	Meter Boxes	Meter boxes are located in the wall of a building and house meters and regulators. Meter boxes are susceptible to corrosion resulting in a compromised seal causing potential migration into building. Also, electrical shorts may occur due to contact between meter box and meter set.
	Plastic Services	Failure to follow safe excavation practices leads to damages (failure to request a locate, provide a locate, provide a correct locate, dig safely).
	Plastic Services with EFV	Plastic services with an Excess Flow Valve (EFV) can be damaged which results in a unnoticeable gas release. If the damaged service is then backfilled without repair, it will result in compromised service to customer.
	Plastic Services with no EFV	Plastic services without an EFV are susceptible to a significant volume of gas release when the service is damaged compared to a service with an EFV installed.
	Stand Pipes	Stand Pipes are abandoned and disconnected termination points from the service. Stand Pipes are susceptible to damage and/or corrosion resulting in migration of water-gas mixture into a building.
	Steel Services	Failure to follow safe excavation practices leads to damages (failure to request a locate, provide a locate, provide a correct locate, dig safely).
	XHP/HP Close to Buildings	Failure of the relief valves, coupled with HP/XHP services close the buildings, may lead to gas migration into an enclosed space.

Asset Class / Issue Category	Asset / Issue	Risk Description
Valves	Blow Off Valves	Blow off valves are susceptible to damages due to height off of main and reduced cover.
	Isolation Valves (Separating Pressures)	Isolation valves that malfunction and leak or are operated incorrectly may cause higher pressures being introduced into lower pressure systems.
	Mainline Valves	Mainline valves may be difficult to access on a timely basis due to location and number of valves required to isolate targeted areas. Mainline valve malfunction may delay response time when operators are required to isolate larger areas.
	Valves with Bonnet Bolts (1.25" to 2")	Corrosion and/or material brittleness of the bolts, may cause valve malfunction and may cause a loss of containment of gas.
	Wing Lock Valves	Wing lock valves may fail if the incorrect application of force (by mechanical/HVAC contractors, homeowners or first responders) is applied resulting in an internal component failure and subsequent loss of containment of gas.
Fittings	Anodeless Risers	Anodeless risers are composed of two pieces; the internal plastic pipe and the external epoxy coated steel casing. The epoxy coating maybe damaged resulting in corrosion of the steel casing. The plastic pipe can be then exposed to sunlight causing it to become brittle over time.
	Bare Steel Drips	Steel drips were originally designed to collect water in the low pressure system. Since most LP systems are now elevated to IP systems they are no longer required or maintained. They are susceptible to corrosion and damages and are difficult to isolate if there is a leak.
	Chicago Fittings	Chicago fitting are susceptible to above ground leaks due to age and ground movement causing fittings to leak.
	Compression Outlet Service Tees	Service may pull out of compression outlet service tee due to external forces (damage or ground movement) resulting in a loss of containment of gas.

Asset Class / Issue Category	Asset / Issue	Risk Description
	Jumpers & Service Extensions	Jumpers and service extensions are located near enclosed spaces and may not be cathodically protected, which could lead to accelerated corrosion.
	Mainline Compression Coupling	Mainline compression couplings when exposed to a point of thrust may result in the separation of the pipelines, resulting in a loss of containment of gas.
	Plastic Punch Tee Cap	Plastic punch tee caps are susceptible to cracking when over-torqued, and may leak.
	Services Downstream of AMP Fittings	The copper riser downstream of AMP fittings may corrode due to age and gas flow rate, resulting in a potential of underground migration of gas.
	Tap-n-Valve Tee	Service lines can be severed due to ground settlement at the tee resulting in a below-ground leak.
	Vintage Plastic Service Tee Cap	Vintage plastic service tee caps are susceptible to brittle like cracking when over-torqued. Cracking may result in a leak.
M&R Equipment	District Stations	District station components may fail due to age or damage, which may result in over / under pressure and/or loss of containment of gas.
	Farm Tap Components	Failure of farm tap components may fail due to age or damage. This can result in over/ under pressure and / or loss of containment of gas.
	Gate Stations (and Feeder Stations)	Failure of gate / feeder station components may fail due to age or damage. This can result in over/ under pressure and / or loss of containment of gas.
	Header Stations	Header station components may fail due to age or damage, which may result in over / under pressure and/or loss of containment of gas.
	Heating Systems	Heating system component failure can result in environmental spills, frost heave and / or over / under pressure of system.
	Inside Regulators	Inside regulators are located inside customer buildings. Damage to the service line could result in a loss of containment inside the building.

Asset Class / Issue Category	Asset / Issue	Risk Description
	Load Changes for Customers	Customers changing load requirements without notifying EGD may result in compromised reliability of service.
	LP Delivery Sales Stations	Low pressure (LP) sales stations components may fail due to age or damage, and may result in over / under pressure and/or loss of containment of gas.
	Multi Cut Regulators	Multi cut regulators may not be identified and shut off properly by first responders when necessary. This may result in over / under pressure of downstream system.
	Odorant	Odorant fade may result from pipe odorant absorption, typically found in low flow one way feeds or new pipes; a leak may not be detected by the public.
	Pounds Delivery Stations	Pounds Delivery stations components may fail due to age or damage which may result in over / under pressure and/or loss of containment of gas.
	Regulator Enclosures	Customers can enclose areas which contain regulators in contravention of code hence an equipment malfunction or venting gas may result in gas build up in an enclosed space.
	Regulators	Regulators may malfunction when water gets into the regulator and freezes. This may lead to over / under pressure downstream of the system.
	Regulator Vent Protection	Regulator vent protection may be inadequate resulting in a regulator malfunction causing over/under pressure of downstream system.
	Residential Meter Set Compliance	Potential inaccurate meter readings may lead to customer billing inaccuracies.
	SCADA / Telemetry	Failure of SCADA / telemetry equipment can result in communication failure to the operators / controllers.
	Single Cut Regulators	Single cut regulator components may fail due to age or damage. This may lead to over / under pressure downstream of the system.

Asset Class / Issue Category	Asset / Issue	Risk Description
General	Asset Records Integrity	Inaccurate, missing or incomplete records may impact operational decisions and safety. System compatibility is a contributing factor for inaccurate, missing or incomplete records.
	Cross Bores (Sewer Lateral)	Third parties can damage a gas line when attempting to clear a sewer. The gas line at the time of installation may have been inadvertently installed through a sewer lateral. Damages would result in a loss of containment of gas.
	Meter Barriers	Above ground assets susceptible to vehicular damage will require adequate protection. Damage to these assets could result in a loss of containment of gas.
	Tracer Wire	Tracer wires can be susceptible to damage, corrosion, and malfunction resulting in difficulty performing locates. Inaccurate locates can result in damages.
Reliability	Reliability of Supply	The inability to shed load off the system can result in unplanned outages. A loss of the upstream supply or damages can result in significant customer outages.
	Single Source Feed (Upstream Supply)	A loss of upstream supply can result in significant customer losses.

Table 12 : Risk Register

Evaluation of Risks

Risks within the risk register were evaluated to establish a relative risk ranking.

In the focus groups described above, the SMAs were consulted to determine the relative risk level for each risk by identifying the likelihood that an adverse condition could be triggered, and the subsequent impact of this event.

The likelihood was determined by discussing the frequency of events related to the particular risk based on historical EGD incidents and the SMA's experience. The impact of the event was also determined by the SMAs, aided by historical events and by estimating the effect on the following consequence categories:

- Customer, Public and Employee Health and Safety
- Physical Damage / Economic Loss
- Environmental Effect
- Regulatory Relationship
- Customer Satisfaction
- Corporate Image

It should be noted that this process relied upon the judgment and experience of the SMAs who work with the assets directly or indirectly on a daily basis. The conclusions drawn were based on arriving at a consensus amongst the SMAs.

In order to better understand and quantify the level of these risks, a change in methodology was introduced as compared to last year's risk prioritization process. This change entailed taking into account the likelihood and impact of the best, likely and worst case scenarios that would result from triggering an event related to each of the risks identified. Existing mitigations were taken into account as part of the assignment of likelihood. This was done to ensure that costs and resources are not allocated to new mitigations when current mitigation may be adequate.

Once the likelihood and impact levels were identified for each case scenario, a double triangular distribution technique was used to aggregate the risks of each scenario into an overall risk level. The double triangular distribution technique is used to approximate the probability distribution representing the outcome of future events based on limited information. Although, two other techniques (normal distribution and triangular distribution) were considered, the double triangular distribution was selected for the following reasons:

- Availability of historical data to validate estimated probabilities and consequences of events was limited
- The mode (the value that appears most often in a set of data) does not coincide with the midpoint of the frequency distribution (i.e. the most likely case for each of the risks occurs as often as the best case)
- The worst case scenario, which often entails catastrophic results, has been experienced to occur with much less frequency than the likely and best case scenarios

The risk ranking approach in the first iteration of the Asset Plan resulted in most risks being assessed based on the worst case scenario being dominant, resulting in several risks being identified in the Priority 1 (P1) area of the Risk Prioritization Likelihood and Impact Chart as shown below.

		Impact				
		Minor	Moderate	Major	Severe	Worst Case
Likelihood	Daily to monthly	P3	P2	P1	P1	P1
	Monthly to yearly	P3	P2	P2	P1	P1
	Once in 1 to 10 years	P3	P3	P2	P2	P1
	Once in 10 to 100 years	P4	P3	P3	P2	P2
	Once in over 100 years	P4	P4	P3	P3	P3

Figure 15 : Risk Prioritization Likelihood and Impact Chart

The enhanced approach to risk assessment, used for the current iteration of the Asset Plan, allowed for a more balanced relative risk ranking. Using the Risk Prioritization Likelihood and Impact Chart, the risks were prioritized into categories with items in the top right corner of the matrix having the greatest relative risk (P1) and items in the bottom left having the least relative risk (P4).

Relative Risk Ranking

The result of the risk assessment and prioritization is summarized in the Risk Prioritization table below, where risks are included in alphabetical order.

	Priority 1	Priority 2	Priority 3
Mains		Carrier Pipe in Casings	Pipelines in AC Susceptible Areas
		Don River Bridge Crossing	Vintage Plastic Mains - Pre 1982
		Field Applied Coatings on Tie-In to Steel	
		High Stress Steel Mains	
		Isolated Steel Mains	
		Older Coated Steel	
		Plastic Mains	
		Segment of the 20-inch Lakeshore Line	
		Vintage Steel Network	
Services		Bare Steel Services (LP/IP)	Copper Services
		Isolated Steel Services	Meter Boxes
		Plastic Services	Plastic Services with EFV
		Plastic Services with no EFV	XHP/HP Close to Buildings
		Stand Pipes	
		Steel Services	
Valves		Blow Off Valves	Valves with Bonnet Bolts (1.25" to 2")
		Isolation Valves (Separating Pressures)	Wing Lock Valves
		Mainline Valves	
Fittings		Anodeless Risers	Plastic Punch Tee Cap
		Bare Steel Drips	Tap-n-Valve Tee
		Chicago Fittings	Vintage Plastic Service Tee Cap
		Compression Outlet Service Tees	
		Jumpers & Service Extensions	
		Mainline Compression Coupling	
		Services Downstream of AMP Fittings	
M&R Equipment		District Stations	Farm Tap Components
		Header Stations	Gate Stations (and Feeder Stations)
		Inside Regulators	Heating Systems
		LP Delivery Sales Stations	Load Changes for Customers
		Multi Cut Regulators	SCADA / Telemetry
		Odorant	

		PSI Delivery Stations	
		Regulator Enclosures	
		Regulators	
		Regulator Vent Protection	
		Residential Meter Set Compliance	
		Single Cut Regulators	
General	Asset Records Integrity	Cross Bores (Sewer Lateral)	Tracer Wire
		Meter Barriers	
Reliability		Reliability of Supply	Single Source Feed (Upstream Supply)

Table 13 : Risk Prioritization

Initiatives Defined to Address Risks

The following table shows the initiatives that have been established to address the risks contained in the risk register. These initiatives are consistent with the Asset Management strategies described in section 4.

The initiatives consist of continuing existing programs, expanding the scope of other existing programs, initiating new programs, and conducting studies to better understand the condition of assets potentially leading to future programs.

Studies entail the identification and validation of appropriate asset records, evaluation and identification of locations to extract specific asset samples, tests and assessment of extracted asset samples, and evaluation of industry related incidents and trends.

As more knowledge is gained through studies, prioritization of certain risks may change.

Asset Class / Issue Category	Asset / Issue	Initiative Name	Initiative Description
Mains	Carrier Pipe in Casings	Casing Study & Program	Study to enhance knowledge of the effectiveness of cathodic protection of the carrier pipe in casing locations and implement targeted remediation program.
	Don River Bridge Crossing	Don River Bridge Crossing Replacement	Determine the need and timing of a replacement solution and implement the solution.
	Field Applied Coatings on Tie-In to Steel	Field Applied Coatings Study	Study to understand issues with field applied coatings on tie-in to steel, and how to resolve them.
	High Stress Steel Mains	ILI and Assessment Program for Pipelines Operating over 20% SMYS	Ongoing ILI and assessment program designed to identify and manage corrosion, mechanical damage and manufacturing defects for pipelines operating over 20% SMYS.
	Isolated Steel Mains	Isolated Steel Mains CP Study	Study and program to cathodically protect isolated steel mains.
	Older Coated Steel	Coated Steel Study & Remediation Program (Mains & Services)	Study to understand the condition of vintage steel mains and services and targeted replacement programs where necessary.
	Pipelines in AC Susceptible Areas	AC Mitigation Program	Remediation program to address targeted pipelines susceptible to AC corrosion.
	Plastic Mains	Pipeline Markers	Installation of pipeline markers on targeted lines to improve pipeline awareness.

Asset Class / Issue Category	Asset / Issue	Initiative Name	Initiative Description
	Segment of the 20-inch Lakeshore Line	20-Inch Lakeshore Line Replacement	Determine the need and timing of a replacement solution and implement the solution.
	Vintage Plastic Mains - Pre 1982	Plastic Mains (incl Services) Study & Replacement	Study to understand plastic pipe susceptibility to cracking and potential targeted remediation program.
	Vintage Steel Network	Replacement Mains	Ongoing program that includes replacement of mains and associated fittings that are either at or near the end of their useful life.
Services	Bare Steel Services (LP/IP)	Bare Steel Services Replacement	Study to determine the level and speed of potential remediation program. Any immediate remediation associated with these services will be conducted under the service relay program.
	Copper Services	Service Relays	Ongoing program that includes the replacement of service lines (relays) to industrial, commercial and residential customers, performed as a result of planned initiatives to improve the integrity of the distribution system.
	Isolated Steel Services		
	Plastic Services		
	Steel Services		
	Meter Boxes	Meter Box Remediation Study and Program	Study and related remediation program to address issues related to shorting and deterioration of meter boxes.
	Plastic Services with EFV	Address through multiple current and new initiatives.	Damage Prevention initiatives, execution of Distribution Records Management Program, and identification of assets in GIS system.
	Plastic Services with no EFV	Excess Flow Valve Retrofit Program (Insertion Method)	A program to determine the appropriate location for EFV's and the most effective method for installation.
	Stand Pipes	Address through multiple current and new initiatives.	Expansion of Excess Flow Valve program, execution of Distribution Records Management program, identification of assets in GIS system, and revisions to system design practices.
	XHP/HP Close to Buildings	Address through multiple current and new initiatives.	Expansion of Excess Flow Valve program, execution of Distribution Records Management program, identification of assets in GIS system, and revisions to system design practices.

Asset Class / Issue Category	Asset / Issue	Initiative Name	Initiative Description
Valves	Blow Off Valves	Address through multiple current and new initiatives.	Execution of ILI and Assessment program, execution of Distribution Records Management program, execution of Coated Steel Remediation program, and identification of assets in GIS system.
	Isolation Valves (Separating Pressures)	Pressure Class Isolation Valve Study and Program	Study followed by a program to define and remove valves.
	Mainline Valves	Address through multiple current and new initiatives.	Retraining of valve operators, revisions to operating and inspection procedures.
	Valves with Bonnet Bolts (1.25" to 2")	Failure of Bonnet Bolts on Valves Study	Study to determine condition of Bonnet Bolts on Valves and to define program requirements if necessary.
	Wing Lock Valves	Wing Lock Valve Study and Replacement	Study to determine the condition of wing lock valves and implement targeted replacement program.
Fittings	Anodeless Risers	Anodeless Riser Study and Program	Study to better understand the nature and extent of corrosion issues associated with anodeless risers, followed by a repair/replacement program as appropriate.
	Bare Steel Drips	Bare Steel Drips Program	Study and removal program for bare steel drips that are now considered obsolete equipment.
	Chicago Fittings	Chicago Fitting Study	Study to determine if a proactive replacement program would be more effective than reactive repair.
	Compression Outlet Service Tees	Compression Outlet Service Tee Remediation Program (Service Relays)	Remediation program to remove at risk compression outlet service tees prior to municipal works programs. The remediation of these fittings will be conducted through the Service Relays Program.
	Jumpers and Service Extensions	Jumper and Service Extension Study and Program	Study to increase knowledge regarding steel jumper and service extension condition and targeted remediation program.
	Mainline Compression Couplings	Compression Couplings Program (Replacement Mains)	Study to identify targeted compression couplings and to install pressure containment sleeves over these couplings. The remediation of these fittings will be conducted through the Replacement Mains Program.

Asset Class / Issue Category	Asset / Issue	Initiative Name	Initiative Description
	Plastic Punch Tee Cap	Punch Tee Cap Study	Study to determine the level and speed of potential remediation program. This includes both vintage and PE punch tees.
	Vintage Plastic Service Tee Cap		
	Services Downstream of AMP Fittings	AMP Fitting Program	Program to replace the AMP fittings and copper riser based on initial study results concluded in 2013. This includes continuous assessment of condition and risk profile.
	Tap-n-Valve Tee	Service Tie-In Shear Protection	This will be addressed through multiple initiatives including Damage Prevention and execution of current construction and maintenance procedures.
M&R Equipment	District Stations	District and Sales Station Replacement Program	Enhance existing district and header station maintenance and replacement programs, and also install filtering capability at targeted locations and standardize station design.
	Header Stations		
	Multi Cut Regulators		
	PSI Delivery Stations		
	Farm Tap Components	Farm Tap Study and Program	Study to determine condition of farm taps and targeted remediation program.
	Gate Stations (and Feeder Stations)	Gate and Select District Station Upgrades	Enhance existing Gate and Select District Station maintenance and replacement programs.
	Heating Systems		
	Odorant		
	SCADA / Telemetry		
	Inside Regulators	Inside Regulators	Removal program of targeted inside regulator locations.
	Regulator Enclosures		
	Load Changes for Customers	Address through multiple current and new initiatives	Revision to customer attachment procedures.

Asset Class / Issue Category	Asset / Issue	Initiative Name	Initiative Description
	LP Delivery Sales Stations	Commercial /Industrial Low Pressure Regulator Program (CLR)	Study to understand the conditions associated with Commercial /Industrial LP Regulators, define a sustainable program and implement a pilot that includes replacement.
	Regulators	Meter Replacement Program	Meter Replacement Program involves the verification and installation of new meters and the removal, testing and repair or disposal of old meters as well as the replacement of regulators.
	Residential Meter Set Compliance		
	Single Cut Regulators		
	Regulator Vent Protection	Address through multiple current and new initiatives.	Current operating and inspection procedures and standards address this risk.
General	Asset Records Integrity	MOP Verification Program	Field verification, remediation and mitigation, including replacement or reinforcement, of targeted pipelines to ensure safe and reliable operation.
		Distribution Records Management Program	This program is a broad set of initiatives to enhance the records management practices-processes, technology and governance related to the management of asset records.
	Cross Bores (Sewer Lateral)	Sewer Safety Program	Inspection and other programs to proactively identify sewer lateral risks, and ensure construction practices do not create new risks.
	Meter Barriers	Address through multiple current and new initiatives.	Installation reflected in Construction and Maintenance procedures.
	Tracer Wire	Address through multiple current and new initiatives.	Installation reflected in Construction and Maintenance procedures.
Reliability	Reliability of Supply	Load Shed Planning	Program to manage load shed areas through targeted valve installations.
		Remote Control Valve Study and Installation	Study to determine where Remote Control Valves should be used to assist the ability to control an emergency, followed by an implementation program.
	Single Source Feed (Upstream Supply)	Station Supply Reliability Study	Study to understand the issues associated with single fed networks and solutions for maintaining reliability of supply in emergency situations.

Table 14 : System Integrity and Reliability Initiatives

As described earlier in the Legislation section of the introduction, the initiatives above comply with CSA Z662-11 and TSSA CAD FS-196-12. Further details showing what legislative requirements dictate or support each of the above-listed initiatives is found in the Appendix.

Implementation Plan and Estimated Capital Investments

The 59 identified asset risks are addressed by current or new studies and programs. The studies allow the Company to understand the conditions of its assets and may not require a mitigation program; however several studies have yielded preliminary results that warrant remediation programs. The breakdown of approaches to be followed to address the 59 identified asset risks are as follows:

- Eight are addressed by conducting studies to better understand the condition of the assets,
- Eleven are addressed by a study followed by an asset specific program,
- Thirty are addressed by asset specific programs currently in place or upcoming in the following years, and
- Ten are addressed through multiple current and new programs such as Damage Prevention, Distribution Records Management Program, identification of assets in GIS system and expansion of Excess Flow Valve program.

The timing, scope and pace of the System Integrity and Reliability initiatives are based on the relative risk ranking, project interdependencies, current work in progress and operational capacity.

Consistent with the risk based approach, Priority 1 and select Priority 2 initiatives are identified early in the schedule. Select Priority 2 and Priority 3 initiatives are scheduled later in the plan. As well, within each initiative, higher risk assets are addressed earlier in the initiative.

In the implementation plan, where a risk study is followed by a program, there is greater certainty, based on failure data and tacit knowledge, that a risk mitigation program will be required, even though the details of the program may still require further refinement. Where a risk study does not have a program specified beyond the study, there is less certainty that a risk mitigation program is needed. The study itself may allow EGD to re-assess the risk as a lower priority.

For individual initiatives, the required capital expenditures were estimated based on the scope of activities to be performed, projected high-level unit costs, and historical spend for similar work.

The figure below summarizes the implementation plan for the initiatives, and provides an estimate for the required capital investments over the 2013 to 2022 period.

<table>
<tr><th>Asset Class / Issue Category</th><th>Asset / Issue</th><th>Initiative Name</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>Forecast (2013 - 2022) ($000)</th></tr>
<tr><td rowspan="11">Mains</td><td>Carrier Pipe in Casings</td><td>Casing Study and Program</td><td>Study</td><td colspan="9">Program</td><td>$5,075</td></tr>
<tr><td>Don River Bridge Crossing</td><td>Don River Bridge Crossing Replacement</td><td></td><td>Program</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$10,200</td></tr>
<tr><td>Field Applied Coatings on tie-in to steel</td><td>Field Applied Coatings Study</td><td>Study</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$360</td></tr>
<tr><td>High Stress Steel Mains</td><td>ILI and Assessment Program for Pipelines Operating over 20% SMYS</td><td colspan="10">Program</td><td>$108,758</td></tr>
<tr><td>Isolated Steel Mains</td><td>Isolated Steel Mains CP Study</td><td></td><td colspan="9">Program</td><td>$796</td></tr>
<tr><td>Older Coated Steel</td><td>Coated Steel Study Remediation Program (Mains & Services)</td><td></td><td colspan="5">Study</td><td colspan="4">Program</td><td>$48,327</td></tr>
<tr><td>Pipelines in AC susceptible areas</td><td>AC Mitigation Program</td><td></td><td colspan="4">Program</td><td></td><td></td><td></td><td></td><td></td><td>$208</td></tr>
<tr><td>Plastic Mains</td><td>Pipeline Markers</td><td colspan="10">Program</td><td>$1,159</td></tr>
<tr><td>Segment of the 20-inch Lakeshore Line</td><td>20-Inch Lakeshore Line Replacement</td><td></td><td>Program</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$5,610</td></tr>
<tr><td>Vintage Plastic Mains - Pre 1982</td><td>Plastic Mains (incl Services) Study & Replacement</td><td>Study</td><td></td><td colspan="8">Program</td><td>$94,262</td></tr>
<tr><td>Vintage Steel Network</td><td>Replacement Mains</td><td colspan="10">Program</td><td>$41,099</td></tr>
<tr><td rowspan="11">Services</td><td>Bare Steel Services (LP/IP)</td><td>Bare Steel Services Replacement</td><td></td><td></td><td>Study</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$208</td></tr>
<tr><td>Copper Services</td><td rowspan="4">Service Relays</td><td rowspan="3" colspan="10">Program</td><td rowspan="3">$35,371</td></tr>
<tr><td>Plastic Services</td></tr>
<tr><td>Steel Services</td></tr>
<tr><td>Isolated Steel Services</td><td colspan="3">Program</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$2,545</td></tr>
<tr><td>Meter Boxes</td><td>Meter Box Remediation Study and Program</td><td></td><td colspan="9">Program</td><td>$1,741</td></tr>
<tr><td>Plastic Service with EFV</td><td>Address through multiple current and new initiatives.</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$0</td></tr>
<tr><td>Plastic Service with no EFV</td><td>Excess Flow Valve Retrofit Program (Insertion Method)</td><td colspan="10">Program</td><td>$27,864</td></tr>
<tr><td>Stand Pipes</td><td>Address through multiple current and new initiatives.</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$0</td></tr>
<tr><td>XHP/HP Close to Buildings</td><td>Address through multiple current and new initiatives.</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$0</td></tr>
<tr><td rowspan="5">Valves</td><td>Blow off valves</td><td>Address through multiple current and new initiatives.</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$0</td></tr>
<tr><td>Isolation Valves (separating pressures)</td><td>Pressure Class Isolation Valve Study and Program</td><td></td><td>Study</td><td colspan="8">Program</td><td>$4,669</td></tr>
<tr><td>Mainline Valves</td><td>Address through multiple current and new initiatives.</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>$0</td></tr>
<tr><td>Valves with Bonnet Bolts (1.25" to 2")</td><td>Failure of Bonnet Bolts on Valves Study</td><td></td><td></td><td></td><td>Study</td><td></td><td></td><td></td><td></td><td></td><td></td><td>$212</td></tr>
<tr><td>Wing Lock Valves</td><td>WingLock Valve Study & Replacement</td><td colspan="2">Study</td><td colspan="8">Program</td><td>$7,848</td></tr>
</table>

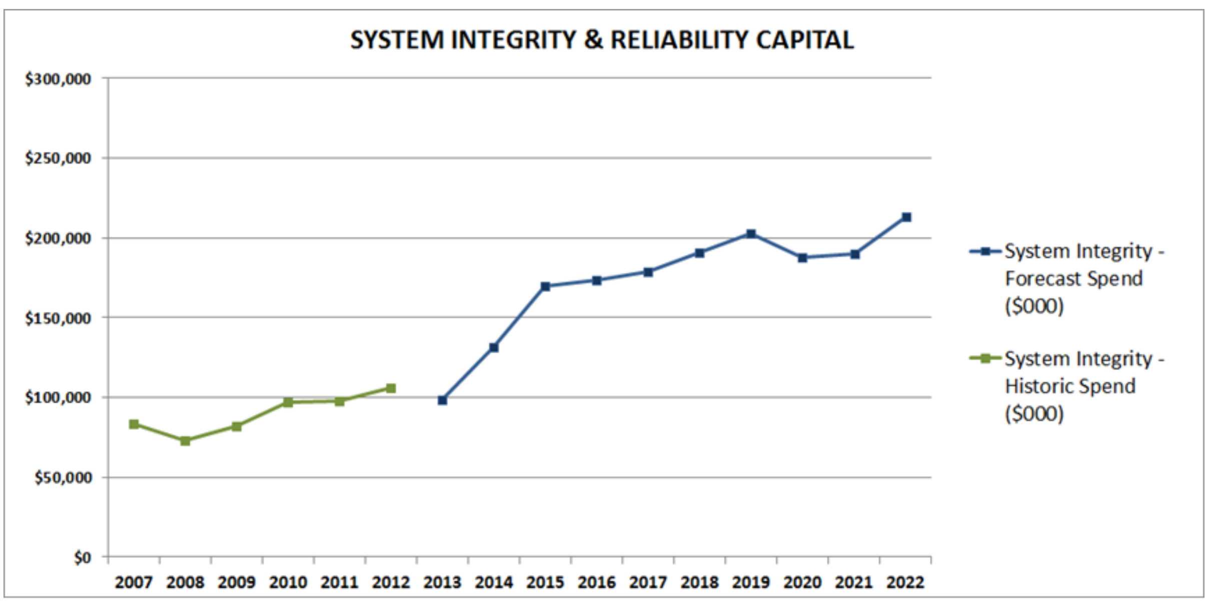
ENBRIDGE

Asset Class / Issue Category	Asset / Issue	Initiative Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013 - 2022) ($000)
Fittings	Anodeless Risers	Anodeless Riser Study and Program					Study		Program				$3,515
	Bare Steel Drips	Bare Steel Drips Program		Study									$255
	Chicago Fittings	Chicago Fitting Study		Study									$204
	Compression Outlet Service Tee	Compression Outlet Service Tee Remediation Program (Service Relays)	Study	Program									$28,959
	Jumpers & Service Extensions	Jumper and Service Extension Study and Program	Study	Program									$1,037
	Mainline Compression Coupling	Compression Couplings Program (Replacement Mains)	Program										$20,081
	Plastic Punch Tee Cap (1.25" and 2")	Punch Tee Cap Study		Study									$408
	Vintage Plastic Service Tee Cap												
	Services downstream of AMP Fittings	AMP Fitting Program	Program										$438,212
	Tap-n-Valve Tee	Service Tie-In Shear Protection											$0
M&R Equipment	District Stations	District/Header Station Equipment Replacement	Program										$85,676
	Header Station												
	Multi Cut Regulator												
	PSI Delivery Stations												
	Farm Tap Components	Farm Tap Study and Program			Study		Program						$815
	Gate Stations (and Feeder Stations)	Gate and Select District Station Upgrades	Program										$95,233
	Heating Systems												
	Odorants												
	SCADA / Telemetry												
	Inside Regulators	Inside Regulators	Program										$410
	Regulator Enclosure												
	Load changes for customers for any sales station	Address through multiple current and new initiatives.											$0
	LP Delivery Sales Stations	Commercial /Industrial Low Pressure Regulator Program (CLR)	Study		Pilot & Program								$45,244
	Regulators	Meter Replacement Program	Program										$279,451
	Residential Meter Set Compliance												
	Single Cut Regulator												
	Regulator Vent Protection.	Address through multiple current and new initiatives.											$0

Asset Class / Issue Category	Asset / Issue	Initiative Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast (2013 - 2022) ($000)
General	Asset Records Integrity	MOP Verification Program	Program										$122,892
		Distribution Records Management Program	Program										$72,619
	Cross Bores (sewer lateral)	Sewer Safety Program	Program										$16,684
	Meter Barriers	Address through multiple current and new initiatives.											Included as part of Customer Growth related M&R
	Tracer Wire	Address through multiple current and new initiatives.											$0
Reliability	Reliability of Supply	Load Shed Management		Program									$22,387
		Remote Control Valve Study & Installation	Study		Program								$68,488
	Single Source Feed (upstream supply)	Station Supply Reliability Study			Study								$520

Figure 16 : System Integrity and Reliability Risk Mitigation Plan

The chart below depicts the capital spend for System Integrity and Reliability



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$83,467	$73,223	$81,905	$97,096	$97,763	$105,854	$98,782	$131,205	$169,544	$173,900	$178,966	$190,514	$202,413	$187,617	$189,682	$213,641

Chart 9 : System Integrity and Reliability Capital Spend

5.5 Relocations

Introduction

A Relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, as a result of direct conflicts with third parties. Gas distribution assets generally need to be relocated for reasons such as road and sewer work and other municipal or third party construction projects.

The Planning and Design group within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, applicable legislation and to ensure the continued safe and reliable delivery of natural gas to customers.

EGD representatives attend the regular meetings of the various municipal Utility Coordinating Committees (UCC) and their sub-committees dealing with capital works. Through these forums, various stakeholders within the Right of Way will discuss projects which may impact others and on occasion, lead to the need to relocate existing plant. Utilities and the municipality will circulate proposals for work at which time the potential to be in conflict with existing infrastructure is identified. Through various means, the work is either redesigned to avoid the conflict or identified as a relocation project. Relocation requirements primarily arise from road realignments and expansions, sewer and water work, bridge rehabilitation, grade separations or other developments that are initiated by a city, municipality or other third party.

When reviewing third party work for potential conflict, the first approach is to avoid or mitigate costs, including the abandonment or removal of the plant in conflict if possible, or through redesign of the proposed plans. Discussions are held in order to mitigate or avoid relocating existing natural gas plant wherever feasible.
Often, due to dealing with multiple agencies within a limited roadway or size and scope of a particular project, relocating existing gas assets is the only solution.

EGD is obligated under its existing franchise agreements and under legislations such as the *Public Service Works on Highways Act* to relocate its plant under various levels of cost sharing when conflicts cannot be avoided. In many cases, based on the agreements in place, EGD is able to recover a portion of the relocation costs from third parties such as municipalities. Where recovery is not available, the entire cost of the work will be borne by the Company.

Municipal capital works lists may have several years of potential projects identified. However, actual detailed planning of these projects cannot begin until the year and month the municipal budgets are approved at council, which is typically in the spring of the same year as construction.

Only when the municipal capital works programs are set, can detailed designs be completed in order to begin planning and estimating costs associated with any required relocation projects. Therefore, when forecasting future years' relocations, EGD begins with a historical base level of relocation spend, and then adds a high level forecast of spend for projects that are considered incremental to that historical relocation activity.

Requirements

On top of the historic actuals costs, where known, EGD considers externalities that may impact the relocation requirements. In the past, such externalities have been the result of increased infrastructure spend from the various levels of government.

EGD experienced such an externality in 2013 when some large scale transit projects have resulted in a considerable step change in relocation activity. These transit projects are forecasted to continue for many years to come.

The York Regional Rapid Transit Corporation Expansion Program is one such transit project that is expected to result in a significant number of relocation projects. As shown in the figure below, the proposed route for the new Bus Rapidways will travel within the right-of-way along Highway 7, Yonge St and Davis Dr. Due to traffic considerations, utility congestion, and construction scheduling, the gas relocation work will be phased over many years (2013-2018). The figure below sets out the overall plan for the YRRTC expansion program.

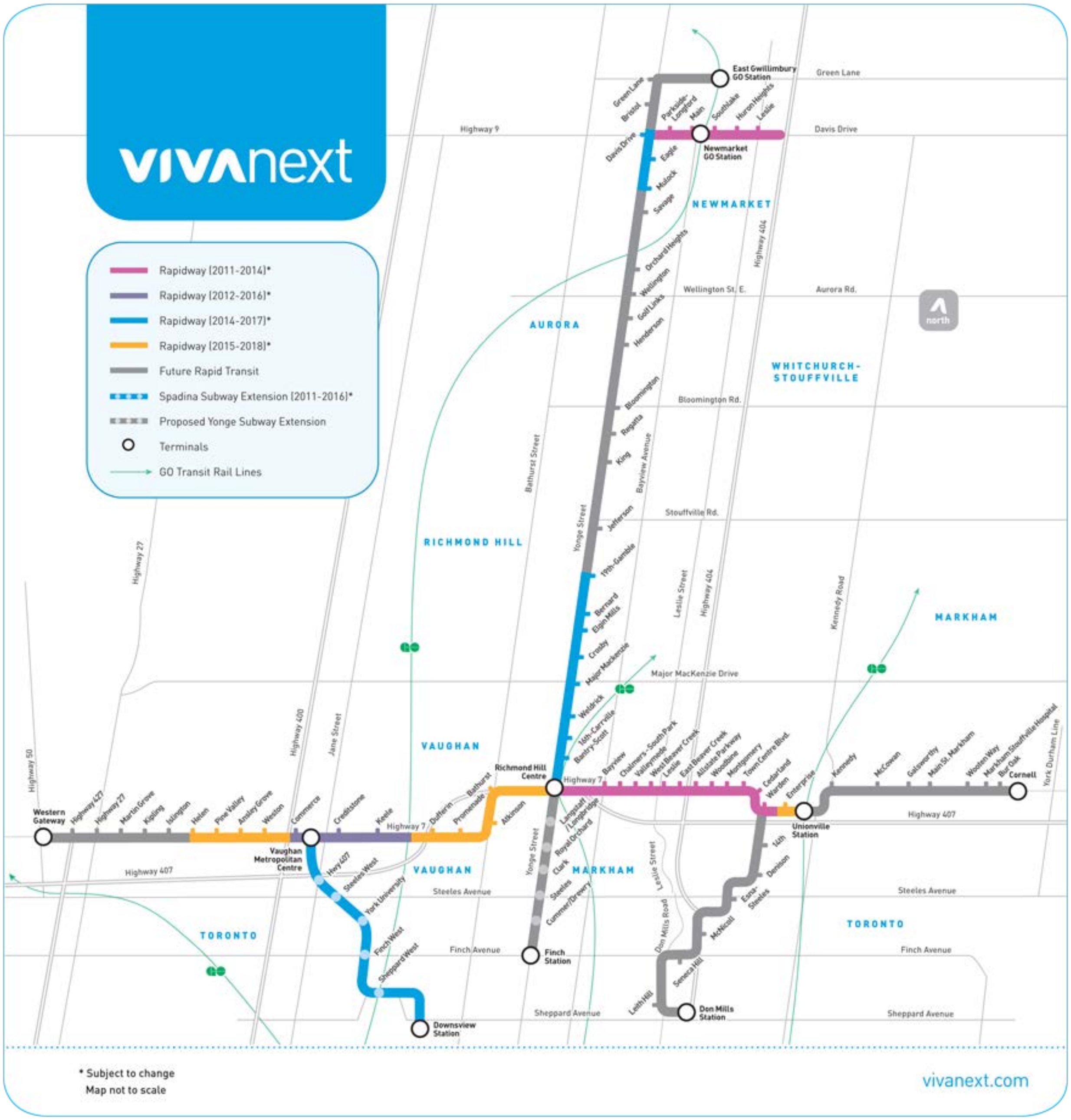
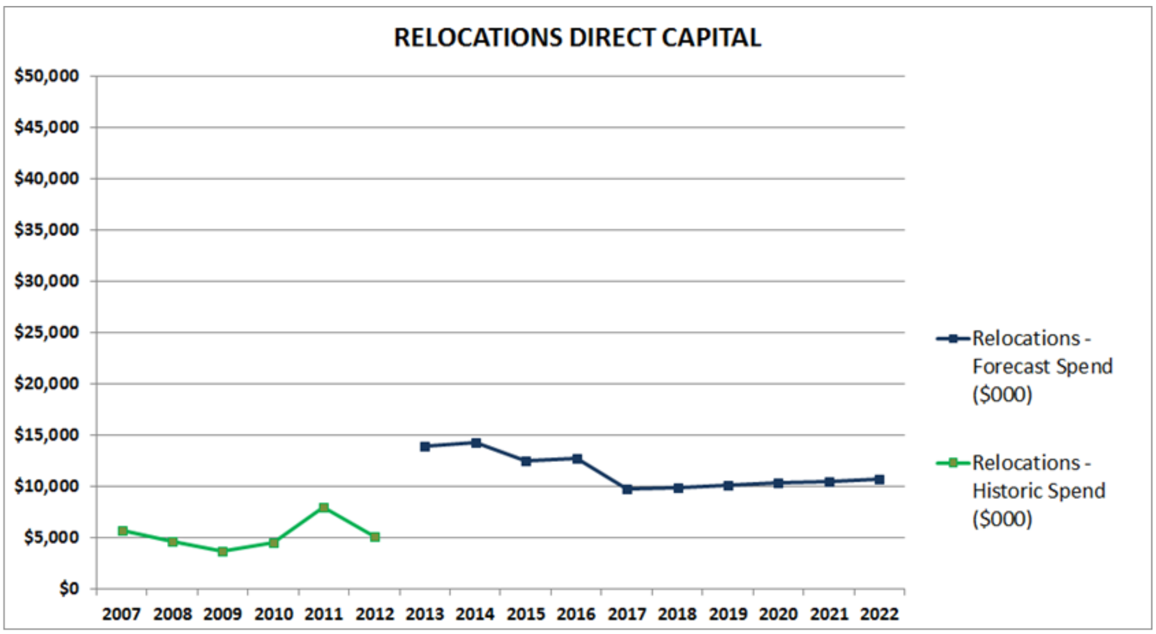


Figure 17 : YRRTC Expansion Program

The Bus Rapidways are dedicated bus routes in the centre of the roadway. This will result in gas relocations to account for station building, road widenings and utility relocations. The roadways affected by this construction work have major arterial gas mains that feed stations and smaller grid mains along the proposed route. Currently, most phases of the Rapidway are still in design and all conflicts have yet to be identified. It is anticipated that much of the gas infrastructure along these routes will eventually have to be relocated to allow for construction to proceed.

Implementation Plan and Estimated Capital Investments

The following chart depicts the historic and forecast capital investments, net of the re-billable portion, required for relocations.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$5,770	$4,717	$3,749	$4,551	$7,965	$5,186	$14,000	$14,280	$12,485	$12,734	$9,742	$9,937	$10,135	$10,338	$10,545	$10,756

Chart 10 : Relocations Capital Spend

A number of significant incremental activities, which are already underway or announced, are driving forecast relocation costs above historical levels. The change from historic levels of spend on relocation projects to the levels shown above for the period of 2013 to 2017 is directly attributable to the recent activity in infrastructure spending in large scale transit projects throughout the franchise.

6. Financial Summary

The table below summarizes the forecasted capital spend profile to meet the four types of asset related requirements within the scope of the Asset Plan.

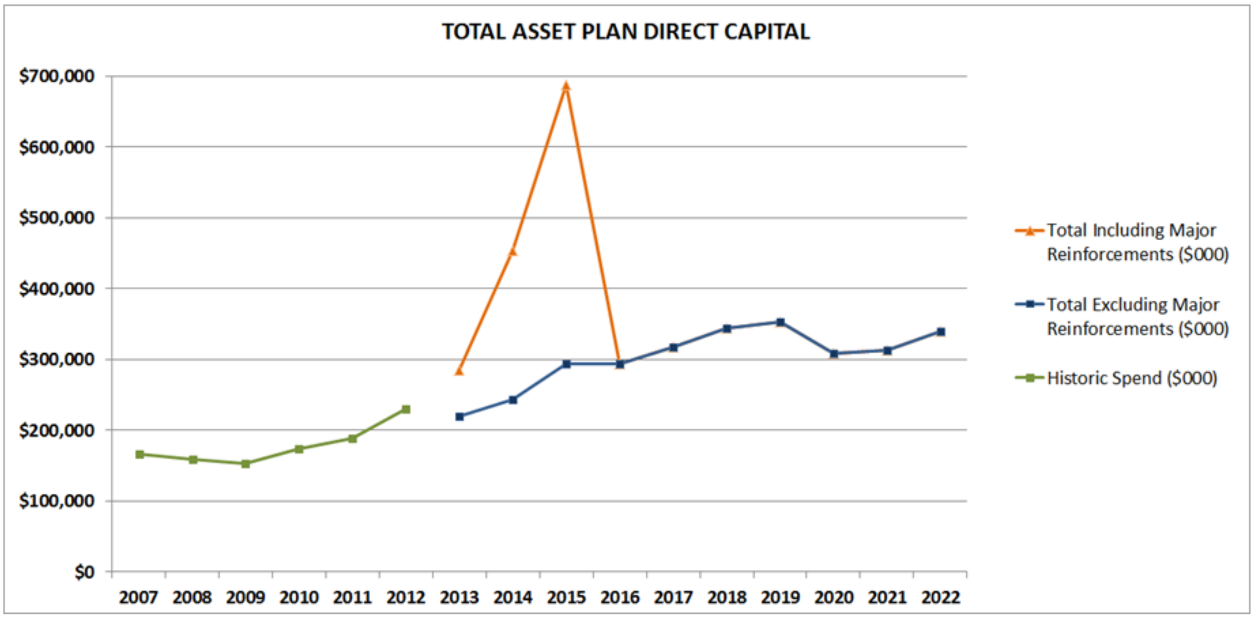
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Customer Additions ($000)	$90,652	$87,835	$94,095	$98,859	$101,015	$104,571	$105,956	$108,137	$110,324	$112,966
Routine Reinforcements ($000)	$16,360	$9,486	$16,959	$8,743	$27,710	$39,305	$34,930	$2,010	$1,757	$1,793
System Integrity and Reliability ($000)	$98,782	$131,205	$169,544	$173,900	$178,966	$190,514	$202,413	$187,617	$189,682	$213,641
Relocations ($000)	$14,000	$14,280	$12,485	$12,734	$9,742	$9,937	$10,135	$10,338	$10,545	$10,756
Total Excluding Major Reinforcements ($000)	$219,794	$242,806	$293,082	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155
Major Reinforcements ($000)	$64,717	$210,370	$394,052	$0	$0	$0	$0	$0	$0	$0
Total Including Major Reinforcements ($000)	$284,511	$453,176	$687,134	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155

Table 15 : Asset Spend by Category of Requirement

The following is a general set of assumptions that was used in developing these forecasts:

- Estimates are based on EGD's asset requirements as of April 2013. Going forward, as part of the annual Asset Planning cycle, these requirements will be reviewed and revised as needed. The capital investment profile is expected to change as the requirements evolve
- The costs included are direct costs only
- For the term 2014-2022, an annual inflation factor of 2% has been assumed

The chart below depict the overall spend for the term of the Asset Plan



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Excluding Major Reinforcements ($000)	$166,355	$158,783	$152,971	$172,927	$187,586	$221,331	$219,794	$242,806	$293,082	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155
Total Including Major Reinforcements ($000)	$166,355	$158,783	$152,971	$172,927	$189,062	$230,069	$284,511	$453,176	$687,134	$294,237	$317,433	$344,327	$353,434	$308,102	$312,309	$339,155

Chart 11 : Total Asset Plan Spend

Appendix

The following table outlines the specific legislative provisions that are applicable to each of the programs and projects contemplated in the System Integrity and Reliability section of this Asset Plan.

Act/Regulation	**O. Reg. 210/01 (CSA Z662)**									**O. Reg. 212/01 (CSA B149)**	**O. Reg. 350/06 (OBC)**	**O. Reg. 453/08 (CSA C22.1)**	**O. Reg. 213/07 (Fire Code)**	**Bill C14**
Clause	3.2.1	10.3	10.3.10	10.15.1.2	12.10.16	12.4.13.1	12.10.2.3	12.10.5	3.2.2	16				
Program/Project														
Mains														
Casing Study & Program	X	X	X		X									
NPS 20 Lakeshore Line Replacement	X	X			X		X							
Don River Bridge Crossing Replacement	X	X	X											
Field Applied Coatings Study	X	X			X		X							
AC Mitigation	X	X	X		X		X							
Pipeline Markers	X	X	X	X	X		X							
ILI for Targeted Pipelines Over 20% SMYS	X	X			X									
Plastic Mains (Including Services) Replacement	X	X			X		X							
Miscellaneous Mains Replacements	X	X			X		X							

Act/Regulation	O. Reg. 210/01 (CSA Z662)									O. Reg. 212/01 (CSA B149)	O. Reg. 350/06 (OBC)	O. Reg. 453/08 (CSA C22.1)	O. Reg. 213/07 (Fire Code)	Bill C14
Clause	3.2.1	10.3	10.3.10	10.15.1.2	12.10.16	12.4.13.1	12.10.2.3	12.10.5	3.2.2	16				
Services														
Bare Steel Services Replacement	X	X			X		X							
Miscellaneous Service Relays	X	X			X		X							
Isolated Steel Remediation Program	X	X			X		X							
Meter Boxes Remediation Program	X	X			X									
EFV Program	X	X			X									
Valves														
Pressure Class Isolation Valves Removal	X	X			X			X						
Failure of Bonnet Bolts on Valves Study	X	X			X									
WingLock Valve Study & Replacement	X	X			X									
Fittings														
Anodeless Riser Replacement	X	X			X									
Bare Steel Drips Program	X	X			X		X							
Chicago Fittings Study	X	X			X		X							
Compression Outlet Service Tee Study	X	X			X		X							

Act/Regulation	O. Reg. 210/01 (CSA Z662)									O. Reg. 212/01 (CSA B149)	O. Reg. 350/06 (OBC)	O. Reg. 453/08 (CSA C22.1)	O. Reg. 213/07 (Fire Code)	Bill C14
Clause	3.2.1	10.3	10.3.10	10.15.1.2	12.10.16	12.4.13.1	12.10.2.3	12.10.5	3.2.2	16				
Jumpers & Service Extension Study	X	X			X		X							
Targeted Compression Coupling Pressure Containment Sleeve Program	X	X			X		X							
Punch Tee Cap Study	X	X			X		X							
AMP Fitting Replacement	X	X			X		X							
M&R Equipment														
Farm Tap Study	X	X			X			X						
District/Header Station Replacement Program	X	X			X			X			X	X	X	
Gate Station Equipment Replacement	X	X			X			X			X	X	X	
Inside Regulators	X	X			X									
Low Pressure Delivery Meter Set Program	X	X			X			X		X				
Meters (MXGI)										X				X
Residential Regulator Refits	X	X			X			X		X				
General														
Verification of MOP	X	X	X		X									
Distribution Records Management Program	X	X			X									
Sewer Safety Program	X	X			X				X					

Act/Regulation	O. Reg. 210/01 (CSA Z662)									O. Reg. 212/01 (CSA B149)	O. Reg. 350/06 (OBC)	O. Reg. 453/08 (CSA C22.1)	O. Reg. 213/07 (Fire Code)	Bill C14
Clause	3.2.1	10.3	10.3.10	10.15.1.2	12.10.16	12.4.13.1	12.10.2.3	12.10.5	3.2.2	16				
Reliability														
Load Shed Management	X					X								
Remote Control Valve Study & Installation	X	X	X		X									
Station Supply Reliability Study	X	X			X			X						

Table 16 : Mapping of System Integrity and Reliability Initiatives to Legislation

UTILITY RATE BASE
2014 FISCAL YEAR

Line No.		Col. 1 2014 Fiscal Year Excl. CIS & Customer Care	Col. 2 2014 Fiscal Year CIS & Customer Care	Col. 3 Total 2014 Fiscal Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	6,977.0	127.1	7,104.1
2.	Accumulated depreciation	(2,895.7)	(69.3)	(2,965.0)
3.	Net property, plant, and equipment	4,081.3	57.8	4,139.1
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.3	-	1.3
5.	Materials and supplies	32.8	-	32.8
6.	Mortgages receivable	0.1	-	0.1
7.	Customer security deposits	(65.7)	-	(65.7)
8.	Prepaid expenses	0.9	-	0.9
9.	Gas in storage	279.9	-	279.9
10.	Working cash allowance	43.2	-	43.2
11.	Total Working Capital	292.5	-	292.5
12.	Utility Rate Base	4,373.8	57.8	4,431.6

Witness: K. Culbert

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	353.1	(120.4)	232.7
2.	Distribution plant	6,311.6	(2,634.3)	3,677.3
3.	General plant	320.5	(140.9)	179.6
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	6,985.7	(2,896.1)	4,089.6
6.	Plant held for future use	1.7	(1.2)	0.5
7.	Sub- total	6,987.4	(2,897.3)	4,090.1
8.	Affiliate Shared Assets Value	(10.4)	1.6	(8.8)
9.	Total property, plant, and equipment	6,977.0	(2,895.7)	4,081.3

Witness: K. Culbert

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	44.4	0.3	-	44.6	(1.0)	43.6	43.4
3.	Structures and improvements (452.00)	19.5	10.4	-	29.9	(0.1)	29.9	22.7
4.	Wells (453.00)	51.0	2.4	(0.5)	52.9	-	52.9	51.2
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	64.2	1.5	(0.1)	65.6	-	65.6	64.4
7.	Compressor equipment (456.00)	104.3	6.3	-	110.6	(0.5)	110.1	106.2
8.	Measuring and regulating equipment (457.00)	14.6	0.1	-	14.7	-	14.7	14.6
9.	Base pressure gas (458.00)	41.0	0.0	-	41.0	-	41.0	41.0
10.	Total	348.4	21.0	(0.5)	368.9	(1.5)	367.3	353.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2013	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2014	Regulatory Adjustments (Note 1)	Utility Balance Dec.2014	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(23.2)	(0.5)	-	-	-	(23.6)	-	(23.6)	(23.4)
3.	Structures and improvements (452.00)	(5.8)	(0.4)	-	-	-	(6.2)	0.1	(6.1)	(5.9)
4.	Wells (453.00)	(17.2)	(0.8)	(0.1)	0.5	-	(17.5)	-	(17.5)	(17.4)
5.	Well equipment (454.00)	(5.6)	(0.5)	-	-	-	(6.2)	-	(6.2)	(5.9)
6.	Field Lines (455.00)	(24.2)	(1.0)	(0.1)	0.1	-	(25.2)	-	(25.2)	(24.7)
7.	Compressor equipment (456.00)	(35.8)	(2.9)	(0.2)	-	-	(38.9)	0.2	(38.7)	(37.2)
8.	Measuring and regulating equipment (457.00)	(5.8)	(0.4)	(0.0)	-	-	(6.2)	-	(6.2)	(6.0)
9.	Total	(117.5)	(6.5)	(0.4)	0.5	-	(123.8)	0.3	(123.6)	(120.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	27.7	-	-	27.7	-	27.7	27.7
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.5	-	-	7.5	-	7.5	7.5
4.	Structures and improvements (472.00)	122.1	8.0	(0.5)	129.6	(0.3)	129.3	125.6
5.	Services, house reg & meter install. (473/474)	2,270.3	106.9	(21.9)	2,355.3	-	2,355.3	2,309.1
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.6
7.	Meters (478)	416.7	21.7	(13.0)	425.4	-	425.4	419.4
8.	Sub-total	2,846.8	136.7	(35.5)	2,948.0	(0.3)	2,947.7	2,891.9
9.	Mains (475)	2,926.1	191.4	(3.9)	3,113.6	(2.2)	3,111.4	3,030.3
10.	Measuring and regulating equip. (477)	377.7	26.3	(2.0)	402.0	(0.5)	401.5	389.4
11.	Sub-total	3,303.8	217.7	(5.8)	3,515.7	(2.7)	3,512.9	3,419.7
12.	Total	6,150.6	354.4	(41.3)	6,463.7	(3.1)	6,460.6	6,311.6

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2014	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2014	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(1.9)	(0.1)	-	-	-	(2.0)	-	(2.0)	(2.0)
2.	Structures and improvements (472.00)	(13.6)	(7.8)	-	0.5	0.3	(20.6)	0.2	(20.4)	(16.9)
3.	Services, house reg & meter install. (473/474)	(1,037.8)	(57.0)	24.9	21.9	13.5	(1,034.5)	-	(1,034.5)	(1,035.0)
4.	NGV station compressors (476)	(1.9)	(0.2)	-	0.1	-	(1.9)	-	(1.9)	(1.9)
5.	Meters (478)	(130.4)	(38.6)	-	13.0	-	(156.0)	-	(156.0)	(143.1)
6.	Mains (475)	(1,231.6)	(78.9)	43.3	3.9	2.4	(1,260.9)	1.7	(1,259.3)	(1,240.9)
7.	Measuring and regulating equip. (477)	(192.0)	(8.4)	0.2	2.0	-	(198.3)	0.5	(197.8)	(194.6)
8.	Total	(2,609.2)	(190.9)	68.4	41.3	16.2	(2,674.2)	2.3	(2,671.9)	(2,634.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	9.0	4.9	-	13.9	(0.2) [1]	13.7	12.0
2.	Office furniture and equipment (483.00)	22.5	4.6	(0.7)	26.4	-	26.4	23.2
3.	Transportation equipment (484.00)	49.5	3.2	(0.9)	51.8	(0.1) [1]	51.8	49.8
4.	NGV conversion kits (484.01)	8.2	0.5	(0.3)	8.5	-	8.5	8.2
5.	Heavy work equipment (485.00)	22.2	0.8	(0.3)	22.7	-	22.7	22.2
6.	Tools and work equipment (486.00)	38.6	1.5	(1.1)	39.0	-	39.0	38.4
7.	Rental equipment (487.70)	1.0	1.4	(0.0)	2.4	-	2.4	1.3
8.	NGV rental compressors (487.80)	3.5	2.0	(0.3)	5.2	-	5.2	3.8
9.	NGV cylinders (484.02 and 487.90)	2.8	0.1	(0.0)	2.9	-	2.9	2.8
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	36.0	5.1	(3.2)	37.9	-	37.9	35.7
12.	Software Aquired/Developed (491.00)	114.5	26.3	(13.7)	127.0	-	127.0	119.2
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	0.0	(0.0)
14.	Total	438.7	50.4	(20.5)	468.6	(127.4)	341.2	320.5

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2014 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2014 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(5.5)	(0.7)	-	-	(6.1)	0.2 [1]	(6.0)	(5.6)
2.	Office furniture and equipment (483.00)	(8.8)	(2.1)	0.7	-	(10.2)	-	(10.2)	(9.5)
3.	Transportation equipment (484.00)	(14.9)	(5.3)	0.9	-	(19.3)	0.1 [1]	(19.2)	(17.1)
4.	NGV conversion kits (484.01)	(5.2)	(0.7)	0.3	-	(5.7)	-	(5.7)	(5.4)
5.	Heavy work equipment (485.00)	(8.2)	(0.8)	0.3	-	(8.8)	-	(8.8)	(8.5)
6.	Tools and work equipment (486.00)	(15.7)	(1.6)	1.1	-	(16.1)	-	(16.1)	(15.9)
7.	Rental equipment (487.70)	(1.0)	(0.0)	0.0	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.3)	(0.3)	0.3	-	(2.4)	-	(2.4)	(2.4)
9.	NGV cylinders (484.02 and 487.90)	(2.0)	(0.4)	0.0	-	(2.3)	-	(2.3)	(2.2)
10.	Communication structures & equip. (488)	(1.1)	(0.4)	-	-	(1.5)	-	(1.5)	(1.3)
11.	Computer equipment (490.00)	(15.3)	(13.1)	3.2	-	(25.1)	-	(25.1)	(20.2)
12.	Software Aquired/Developed (491.00)	(45.0)	(28.2)	13.7	-	(59.5)	-	(59.5)	(52.0)
13.	CIS (491.00)	(54.0)	(12.7)	-	-	(66.7)	66.7 [2]	-	-
14.	Total	(179.0)	(66.2)	20.5	-	(224.6)	66.9	(157.7)	(140.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2014	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2014	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2014	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2014	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.2)	(0.0)	-	-	(1.2)	-	(1.2)	(1.2)
2.	Total	(1.2)	(0.0)	-	-	(1.2)	-	(1.2)	(1.2)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 FISCAL YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	0.7	32.3	0.1	(66.7)	0.5	399.7	43.2	409.8
2.	January 31	1.3	32.4	0.1	(66.1)	0.7	254.7	43.2	266.3
3.	February	1.3	32.5	0.1	(65.3)	0.4	134.2	43.2	146.4
4.	March	1.3	32.6	0.1	(65.3)	0.5	47.8	43.2	60.2
5.	April	1.3	32.6	0.1	(65.2)	1.0	60.1	43.2	73.1
6.	May	1.3	32.7	0.1	(65.2)	0.9	123.5	43.2	136.5
7.	June	1.3	32.8	0.1	(65.2)	0.9	201.2	43.2	214.3
8.	July	1.3	32.8	0.1	(65.1)	0.8	293.1	43.2	306.2
9.	August	1.3	32.9	0.1	(65.1)	2.1	385.4	43.2	399.9
10.	September	1.3	33.0	0.1	(65.8)	1.6	469.1	43.2	482.5
11.	October	1.2	33.0	0.1	(66.2)	1.0	508.6	43.2	520.9
12.	November	1.2	33.1	0.1	(66.9)	0.7	483.8	43.2	495.2
13.	December	1.2	33.2	0.1	(66.1)	0.5	396.0	43.2	408.1
14.	Avg. of monthly avgs.	1.3	32.8	0.1	(65.7)	0.9	279.9	43.2	292.5

Witness: K. Culbert

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2014 FISCAL YEAR

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,469.5	8.8	35.4
2.	Items not subject to working cash allowance (Note 1)	(13.6)		
3.	Gas costs charged to operations	1,455.9		
4.	Operation and Maintenance	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	(5.0)	(4.5)
9.	Sub-total			30.9
10.	Storage costs	7.2	71.9	1.4
11.	Storage municipal and capital taxes	1.3	29.3	0.1
12.	Sub-total			1.5
13.	Harmonized Sales Tax			10.8
14.	Total working cash allowance			43.2

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

Witness: K. Culbert

GROSS CUSTOMER ADDITIONS

1. The customer additions forecast for the 2014 to 2016 period, in addition to the 2013 ADR budget, is outlined in Table 1. The forecast projects a slight decline in 2014 customer additions followed by an upward trend for the remaining forecast period. This trend is consistent with the housing starts forecast outlined in the Key Economic Assumptions, Exhibit C, Tab 1, Schedule 1.

TABLE 1

Item No.	Sector	*Col. 1* ADR Budget 2013	*Col. 2* Budget 2014	*Col. 3* Budget 2015	*Col. 4* Budget 2016
	Residential[1]				
1.1	New Construction	29,533	26,967	28,950	30,582
1.2	Replacement	6,492	7,221	6,981	6,448
1.0	Total Residential	36,025	34,188	35,931	37,030
	Commercial[2]				
2.1	New Construction	1,748	1,667	1,776	1,811
2.2	Replacement	796	788	779	801
2.0	Total Commercial	2,544	2,455	2,555	2,612
	Industrial				
3.1	New Construction	9	2	3	3
3.2	Replacement	1	2	0	0
3.0	Total Industrial	10	4	3	3
4.0	Total Gross Customer Additions	38,579	36,647	38,489	39,645

[1] Residential customers include single homes and apartment ensuites
[2] Commercial customers include commercial and traditional apartment buildings

Witnesses: F. Ahmad
L. Au
T. Knight

2. The customer additions forecast has been developed using a number of sources. Information considered in developing this forecast includes on-the-ground realities such as development projects, originating from direct contact with builders, developers, and municipalities. Economic factors and indicators considered, as available from reliable third-party data sources, include housing starts forecasts, GDP growth, employment and mortgage rates. The approach used to develop this forecast is consistent with the approach used by the Company in previous rate applications, and has been accepted in previous settlement proposals and Board decisions.

Residential Customers

3. The residential sector consists of new construction and replacement markets, accounting for over 93% of the customer additions forecast. Residential replacement customers are existing homes that switch from other energy sources to natural gas. Relative to the 2013 ADR budget[1], customer additions in the new construction market are expected to exhibit a slight decline in 2014 and 2015, bouncing back in 2016 to totals that surpass the ADR reference point. The declines in 2014 and 2015 will be partly off-set by an increase in customer growth in the replacement sector. The relative strength of customer growth in the replacement sector is driven by a favourable price advantage of natural gas relative to alternative fuels such as electricity, propane and heating oil. The price advantage experienced by natural gas is predicted to increase going forward.

[1] 2013 ADR budget is the most recent forecast, which was settled during 2013 ADR process

Commercial Customers

4. The continued economic recovery is expected to encourage investments in the commercial sector. Customer growth is expected in both components of this sector, apartment traditional and commercial. Compared to the 2013 ADR Budget, the Company expects flat growth in the commercial sector both in the new construction and replacement markets.

Industrial Customers

5. Prospects of investments in the industrial manufacturing sector in Ontario are not expected to be as strong as 2013 ADR Budget. The Company is forecasting less than four industrial customer additions in any given year during the forecast period.

Witnesses: F. Ahmad
L. Au
T. Knight

UTILITY RATE BASE
2015 FORECAST YEAR

Line No.		Col. 1 2015 Forecast Year Excl. CIS & Customer Care	Col. 2 2015 Forecast Year CIS & Customer Care	Col. 3 Total 2015 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	7,441.0	127.1	7,568.1
2.	Accumulated depreciation	(3,000.6)	(82.0)	(3,082.6)
3.	Net property, plant, and equipment	4,440.4	45.1	4,485.5
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.3	-	1.3
5.	Materials and supplies	33.7	-	33.7
6.	Mortgages receivable	0.1	-	0.1
7.	Customer security deposits	(65.1)	-	(65.1)
8.	Prepaid expenses	0.9	-	0.9
9.	Gas in storage	291.2	-	291.2
10.	Working cash allowance	50.0	-	50.0
11.	Total Working Capital	312.1	-	312.1
12.	Utility Rate Base	4,752.5	45.1	4,797.6

Witness: K. Culbert

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	374.8	(127.2)	247.6
2.	Distribution plant	6,729.8	(2,704.9)	4,024.9
3.	General plant	345.1	(169.0)	176.1
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	7,450.2	(3,001.6)	4,448.6
6.	Plant held for future use	1.7	(1.2)	0.5
7.	Sub- total	7,451.9	(3,002.8)	4,449.1
8.	Affiliate Shared Assets Value	(10.9)	2.2	(8.7)
9.	Total property, plant, and equipment	7,441.0	(3,000.6)	4,440.4

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	44.6	0.9	-	45.5	(1.0)	44.5	43.8
3.	Structures and improvements (452.00)	29.9	8.1	-	38.0	(0.1)	38.0	32.7
4.	Wells (453.00)	52.9	6.8	-	59.6	-	59.6	55.6
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	65.6	2.8	-	68.4	-	68.4	66.2
7.	Compressor equipment (456.00)	110.6	2.9	-	113.4	(0.5)	113.0	111.2
8.	Measuring and regulating equipment (457.00)	14.7	0.0	-	14.7	-	14.7	14.7
9.	Base pressure gas (458.00)	41.0	0.0	-	41.0	-	41.0	41.0
10.	Total	368.9	21.4	-	390.2	(1.5)	388.7	374.8

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2015	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2015	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(23.6)	(0.5)	-	-	-	(24.1)	-	(24.1)	(23.8)
3.	Structures and improvements (452.00)	(6.2)	(0.6)	-	-	-	(6.8)	0.1	(6.7)	(6.4)
4.	Wells (453.00)	(17.5)	(0.9)	(0.0)	-	-	(18.4)	-	(18.4)	(18.0)
5.	Well equipment (454.00)	(6.2)	(0.5)	-	-	-	(6.7)	-	(6.7)	(6.4)
6.	Field Lines (455.00)	(25.2)	(1.0)	(0.1)	-	-	(26.4)	-	(26.4)	(25.8)
7.	Compressor equipment (456.00)	(38.9)	(3.0)	(0.2)	-	-	(42.0)	0.2	(41.8)	(40.3)
8.	Measuring and regulating equipment (457.00)	(6.2)	(0.5)	(0.0)	-	-	(6.7)	-	(6.7)	(6.4)
9.	Total	(123.8)	(6.9)	(0.3)	-	-	(131.1)	0.3	(130.8)	(127.2)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	27.7	1.3	-	29.0	-	29.0	28.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.5	89.4	-	96.8	-	96.8	26.1
4.	Structures and improvements (472.00)	129.6	8.1	(1.9)	135.8	(0.3)	135.5	132.6
5.	Services, house reg & meter install. (473/474)	2,355.3	115.1	(22.3)	2,448.1	-	2,448.1	2,397.1
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.6
7.	Meters (478)	425.4	24.1	(13.0)	436.5	-	436.5	429.2
8.	Sub-total	2,948.0	238.1	(37.3)	3,148.8	(0.3)	3,148.5	3,015.5
9.	Mains (475)	3,113.6	611.8	(4.0)	3,721.5	(2.2)	3,719.3	3,284.1
10.	Measuring and regulating equip. (477)	402.0	107.6	(2.0)	507.7	(0.5)	507.1	430.3
11.	Sub-total	3,515.7	719.4	(6.0)	4,229.1	(2.7)	4,226.4	3,714.4
12.	Total	6,463.7	957.5	(43.2)	7,377.9	(3.1)	7,374.9	6,729.8

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2015	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2015	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.0)	(0.3)	-	-	-	(2.3)	-	(2.3)	(2.1)
2.	Structures and improvements (472.00)	(20.6)	(8.3)	-	1.9	0.8	(26.2)	0.2	(26.0)	(22.8)
3.	Services, house reg & meter install. (473/474)	(1,034.5)	(59.1)	23.0	22.3	13.4	(1,035.0)	-	(1,035.0)	(1,033.7)
4.	NGV station compressors (476)	(1.9)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(1.9)
5.	Meters (478)	(156.0)	(39.5)	-	13.0	-	(182.5)	-	(182.5)	(169.2)
6.	Mains (475)	(1,260.9)	(85.1)	40.2	4.0	2.4	(1,299.5)	1.7	(1,297.8)	(1,274.1)
7.	Measuring and regulating equip. (477)	(198.3)	(9.2)	0.2	2.0	-	(205.3)	0.5	(204.8)	(201.1)
8.	Total	(2,674.2)	(201.7)	63.4	43.2	16.6	(2,752.8)	2.4	(2,750.3)	(2,704.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	13.9	3.1	-	17.0	(0.2) [1]	16.8	15.9
2.	Office furniture and equipment (483.00)	26.4	4.7	(0.3)	30.8	-	30.8	27.3
3.	Transportation equipment (484.00)	51.8	3.2	(0.9)	54.1	(0.1) [1]	54.0	52.1
4.	NGV conversion kits (484.01)	8.5	0.1	(0.3)	8.3	-	8.3	8.4
5.	Heavy work equipment (485.00)	22.7	0.8	(0.3)	23.2	-	23.2	22.8
6.	Tools and work equipment (486.00)	39.0	1.5	(1.0)	39.4	-	39.4	38.8
7.	Rental equipment (487.70)	2.4	1.4	(0.0)	3.8	-	3.8	2.7
8.	NGV rental compressors (487.80)	5.2	2.1	(0.3)	7.1	-	7.1	5.6
9.	NGV cylinders (484.02 and 487.90)	2.9	0.5	(0.0)	3.4	-	3.4	3.0
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	37.9	6.0	(10.0)	33.9	-	33.9	34.4
12.	Software Aquired/Developed (491.00)	127.0	27.0	(20.4)	133.6	-	133.6	127.9
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	-	58.6	-	58.6	-	58.6	2.4
15	Total	468.6	109.0	(33.4)	544.1	(127.4)	416.8	345.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2015 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2015 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(6.1)	(1.1)	-	-	(7.2)	0.2 [1]	(7.1)	(6.5)
2.	Office furniture and equipment (483.00)	(10.2)	(2.6)	0.3	-	(12.5)	-	(12.5)	(11.3)
3.	Transportation equipment (484.00)	(19.3)	(5.5)	0.9	-	(23.9)	0.1 [1]	(23.8)	(21.5)
4.	NGV conversion kits (484.01)	(5.7)	(0.8)	0.3	-	(6.2)	-	(6.2)	(5.9)
5.	Heavy work equipment (485.00)	(8.8)	(0.8)	0.3	-	(9.3)	-	(9.3)	(9.0)
6.	Tools and work equipment (486.00)	(16.1)	(1.6)	1.0	-	(16.7)	-	(16.7)	(16.4)
7.	Rental equipment (487.70)	(1.0)	(0.0)	0.0	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.4)	(0.4)	0.3	-	(2.6)	-	(2.6)	(2.5)
9.	NGV cylinders (484.02 and 487.90)	(2.3)	(0.4)	0.0	-	(2.7)	-	(2.7)	(2.5)
10.	Communication structures & equip. (488)	(1.5)	(0.4)	-	-	(1.9)	-	(1.9)	(1.7)
11.	Computer equipment (490.00)	(25.1)	(12.7)	10.0	-	(27.8)	-	(27.8)	(26.6)
12.	Software Aquired/Developed (491.00)	(59.5)	(29.9)	20.4	-	(68.9)	-	(68.9)	(64.0)
13.	CIS (491.00)	(66.7)	(12.7)	-	-	(79.4)	79.4 [2]	-	-
14.	Total	(224.6)	(68.7)	33.4	-	(260.0)	79.7	(180.3)	(169.0)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2015	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2015	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Opening Balance Dec.2014	Additions	Retirements	Costs Net of Proceeds	Closing Balance Dec.2015	Regulatory Adjustment	Utility Balance Dec.2015	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.2)	(0.0)	-	-	(1.3)	-	(1.3)	(1.2)
2.	Total	(1.2)	(0.0)	-	-	(1.3)	-	(1.3)	(1.2)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 FORECAST YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.2	33.2	0.1	(66.1)	0.5	382.4	50.0	401.3
2.	January 31	1.3	33.3	0.1	(65.6)	0.7	262.2	50.0	282.0
3.	February	1.3	33.4	0.1	(64.8)	0.4	143.4	50.0	163.8
4.	March	1.3	33.5	0.1	(64.7)	0.5	44.9	50.0	65.6
5.	April	1.3	33.5	0.1	(64.7)	1.0	55.8	50.0	77.0
6.	May	1.3	33.6	0.1	(64.7)	0.9	120.3	50.0	141.5
7.	June	1.3	33.7	0.1	(64.6)	0.9	211.7	50.0	233.1
8.	July	1.3	33.8	0.1	(64.6)	0.8	315.3	50.0	336.7
9.	August	1.3	33.8	0.1	(64.6)	2.2	419.5	50.0	442.3
10.	September	1.3	33.9	0.1	(65.3)	1.7	502.1	50.0	523.8
11.	October	1.3	34.0	0.1	(65.7)	1.0	536.8	50.0	557.5
12.	November	1.4	34.0	0.1	(66.4)	0.7	501.1	50.0	520.9
13.	December	1.4	34.1	-	(65.6)	0.6	379.3	50.0	399.8
14.	Avg. of monthly avgs.	1.3	33.7	0.1	(65.1)	0.9	291.2	50.0	312.1

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2015 FORECAST YEAR

Line No.		Col. 1 Disbursements ($Millions)	Col. 2 Net Lag-Days (Days)	Col. 3 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges	1,621.1	8.9	39.5
2.	Items not subject to working cash allowance (Note 1)	(14.3)		
3.	Gas costs charged to operations	1,606.8		
4.	Operation and Maintenance	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	(4.9)	(4.3)
9.	Sub-total			35.2
10.	Storage costs	8.0	66.6	1.5
11.	Storage municipal and capital taxes	1.3	29.3	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			13.2
14.	Total working cash allowance			50.0

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

UTILITY RATE BASE
2016 FORECAST YEAR

Line No.		Col. 1 2016 Forecast Year Excl. CIS & Customer Care	Col. 2 2016 Forecast Year CIS & Customer Care	Col. 3 Total 2016 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,321.9	127.1	8,449.0
2.	Accumulated depreciation	(3,118.7)	(94.7)	(3,213.4)
3.	Net property, plant, and equipment	5,203.2	32.4	5,235.6
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.1	-	40.1
11.	Total Working Capital	288.8	-	288.8
12.	Utility Rate Base	5,492.0	32.4	5,524.4

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	392.9	(134.3)	258.6
2.	Distribution plant	7,522.3	(2,795.0)	4,727.3
3.	General plant	416.4	(190.4)	226.0
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	8,332.1	(3,120.2)	5,211.9
6.	Plant held for future use	1.7	(1.3)	0.4
7.	Sub- total	8,333.8	(3,121.5)	5,212.3
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	8,321.9	(3,118.7)	5,203.2

Witness: K. Culbert

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	45.5	-	-	45.5	(1.0)	44.5	44.5
3.	Structures and improvements (452.00)	38.0	6.6	(0.5)	44.1	(0.1)	44.1	39.0
4.	Wells (453.00)	59.6	5.5	-	65.2	-	65.2	62.5
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	68.4	1.1	(0.1)	69.4	-	69.4	68.6
7.	Compressor equipment (456.00)	113.4	0.2	-	113.7	(0.5)	113.2	113.0
8.	Measuring and regulating equipment (457.00)	14.7	0.0	-	14.7	-	14.7	14.7
9.	Base pressure gas (458.00)	41.0	-	-	41.0	-	41.0	41.0
10.	Total	390.2	13.5	(0.6)	403.1	(1.5)	401.6	392.9

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2016	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2016	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(24.1)	(0.5)	-	-	-	(24.6)	-	(24.6)	(24.3)
3.	Structures and improvements (452.00)	(6.8)	(0.7)	-	0.5	-	(7.0)	0.1	(6.9)	(6.8)
4.	Wells (453.00)	(18.4)	(1.0)	(0.0)	-	-	(19.5)	-	(19.5)	(18.9)
5.	Well equipment (454.00)	(6.7)	(0.5)	-	-	-	(7.2)	-	(7.2)	(7.0)
6.	Field Lines (455.00)	(26.4)	(1.1)	(0.1)	0.1	-	(27.4)	-	(27.4)	(26.9)
7.	Compressor equipment (456.00)	(42.0)	(3.1)	(0.2)	-	-	(45.2)	0.2	(45.0)	(43.4)
8.	Measuring and regulating equipment (457.00)	(6.7)	(0.5)	(0.0)	-	-	(7.1)	-	(7.1)	(6.9)
9.	Total	(131.1)	(7.2)	(0.3)	0.6	-	(138.0)	0.3	(137.7)	(134.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	29.0	-	-	29.0	-	29.0	29.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	96.8	-	-	96.8	-	96.8	96.8
4.	Structures and improvements (472.00)	135.8	6.5	(4.8)	137.5	(0.3)	137.2	134.9
5.	Services, house reg & meter install. (473/474)	2,448.1	134.4	(22.6)	2,559.9	-	2,559.9	2,498.1
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.6
7.	Meters (478)	436.5	26.7	(13.5)	449.7	-	449.7	441.1
8.	Sub-total	3,148.8	167.7	(41.1)	3,275.5	(0.3)	3,275.1	3,202.5
9.	Mains (475)	3,721.5	194.8	(4.0)	3,912.2	(2.2)	3,910.0	3,802.8
10.	Measuring and regulating equip. (477)	507.7	25.4	(2.0)	531.0	(0.5)	530.5	517.0
11.	Sub-total	4,229.1	220.1	(6.1)	4,443.2	(2.7)	4,440.5	4,319.8
12.	Total	7,377.9	387.8	(47.1)	7,718.7	(3.1)	7,715.6	7,522.3

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2016	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2016	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.3)	(1.1)	-	-	-	(3.4)	-	(3.4)	(2.8)
2.	Structures and improvements (472.00)	(26.2)	(8.5)	-	4.8	1.4	(28.5)	0.2	(28.3)	(25.9)
3.	Services, house reg & meter install. (473/474)	(1,035.0)	(61.6)	21.2	22.6	12.7	(1,040.1)	-	(1,040.1)	(1,036.6)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(2.0)
5.	Meters (478)	(182.5)	(40.6)	-	13.5	-	(209.7)	-	(209.7)	(196.0)
6.	Mains (475)	(1,299.5)	(99.6)	37.1	4.0	2.2	(1,355.8)	1.8	(1,354.0)	(1,322.6)
7.	Measuring and regulating equip. (477)	(205.3)	(11.1)	0.2	2.0	-	(214.2)	0.5	(213.7)	(209.2)
8.	Total	(2,752.8)	(222.7)	58.4	47.1	16.3	(2,853.7)	2.6	(2,851.1)	(2,795.0)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	17.0	0.3	-	17.3	(0.2) [1]	17.1	16.9
2.	Office furniture and equipment (483.00)	30.8	4.4	(1.0)	34.1	-	34.1	31.3
3.	Transportation equipment (484.00)	54.1	3.7	(0.9)	56.9	(0.1) [1]	56.8	54.4
4.	NGV conversion kits (484.01)	8.3	0.1	(0.3)	8.2	-	8.2	8.2
5.	Heavy work equipment (485.00)	23.2	1.3	(0.3)	24.3	-	24.3	23.4
6.	Tools and work equipment (486.00)	39.4	1.5	(1.1)	39.8	-	39.8	39.2
7.	Rental equipment (487.70)	3.8	1.4	(0.0)	5.2	-	5.2	4.1
8.	NGV rental compressors (487.80)	7.1	2.2	(0.3)	9.0	-	9.0	7.5
9.	NGV cylinders (484.02 and 487.90)	3.4	0.6	(0.0)	3.9	-	3.9	3.5
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	33.9	8.2	(6.9)	35.2	-	35.2	32.5
12.	Software Aquired/Developed (491.00)	133.6	23.0	(31.2)	125.4	-	125.4	127.4
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	58.6	12.1	-	70.6	-	70.6	64.1
14.	Total	544.1	58.7	(42.0)	560.8	(127.4)	433.5	416.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2016 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2016 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(7.2)	(1.1)	-	-	(8.3)	0.2 [1]	(8.2)	(7.6)
2.	Office furniture and equipment (483.00)	(12.5)	(3.0)	1.0	-	(14.5)	-	(14.5)	(13.5)
3.	Transportation equipment (484.00)	(23.9)	(5.7)	0.9	-	(28.7)	0.1 [1]	(28.6)	(26.2)
4.	NGV conversion kits (484.01)	(6.2)	(0.7)	0.3	-	(6.7)	-	(6.7)	(6.4)
5.	Heavy work equipment (485.00)	(9.3)	(0.8)	0.3	-	(9.8)	-	(9.8)	(9.6)
6.	Tools and work equipment (486.00)	(16.7)	(1.6)	1.1	-	(17.3)	-	(17.3)	(17.0)
7.	Rental equipment (487.70)	(1.0)	(0.0)	0.0	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.6)	(0.6)	0.3	-	(2.9)	-	(2.9)	(2.7)
9.	NGV cylinders (484.02 and 487.90)	(2.7)	(0.4)	0.0	-	(3.1)	-	(3.1)	(2.9)
10.	Communication structures & equip. (488)	(1.9)	(0.4)	-	-	(2.2)	-	(2.2)	(2.0)
11.	Computer equipment (490.00)	(27.8)	(11.9)	6.9	-	(32.7)	-	(32.7)	(30.3)
12.	Software Aquired/Developed (491.00)	(68.9)	(29.4)	31.2	-	(67.1)	-	(67.1)	(68.1)
13.	CIS (491.00)	(79.4)	(12.7)	-	-	(92.2)	92.2 [2]	-	-
14	WAMS (489.00)	-	(6.4)	-	-	(6.4)	-	(6.4)	(3.1)
15	Total	(260.0)	(74.8)	42.0	-	(292.8)	92.4	(200.4)	(190.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T10.S1)

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2016	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2016	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2016	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2016	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2015	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2016	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2016	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)
2.	Total	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2016 FORECAST YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	34.1	-	(65.6)	0.6	381.4	40.1	392.0
2.	January 31	1.4	34.2	-	(65.1)	0.7	227.6	40.1	238.9
3.	February	1.4	34.3	-	(64.3)	0.4	105.1	40.1	117.0
4.	March	1.4	34.4	-	(64.3)	0.5	36.8	40.1	48.9
5.	April	1.4	34.5	-	(64.2)	1.0	48.3	40.1	61.1
6.	May	1.4	34.5	-	(64.2)	0.9	116.4	40.1	129.1
7.	June	1.4	34.6	-	(64.1)	0.9	203.5	40.1	216.4
8.	July	1.3	34.7	-	(64.1)	0.8	299.5	40.1	312.3
9.	August	1.3	34.8	-	(64.1)	2.2	396.1	40.1	410.4
10.	September	1.3	34.9	-	(64.8)	1.7	481.3	40.1	494.5
11.	October	1.3	34.9	-	(65.2)	1.1	524.4	40.1	536.6
12.	November	1.3	35.0	-	(65.9)	0.7	495.5	40.1	506.7
13.	December	1.3	35.1	-	(65.1)	0.6	380.0	40.1	392.0
14.	Avg. of monthly avgs.	1.4	34.6	-	(64.6)	1.0	276.3	40.1	288.8

Witness: K. Culbert

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 FORECAST YEAR

Line No.		Col. 1 Disbursements ($Millions)	Col. 2 Net Lag-Days (Days)	Col. 3 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges	1,647.2	8.8	39.7
2.	Items not subject to working cash allowance (Note 1)	(14.7)		
3.	Gas costs charged to operations	1,632.5		
4.	Operation and Maintenance	339.2		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	330.8		
7.	Ancillary customer services	-		
8.		330.8	(4.4)	(4.0)
9.	Sub-total			35.7
10.	Storage costs	8.4	64.9	1.5
11.	Storage municipal and capital taxes	1.4	29.4	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			2.8
14.	Total working cash allowance			40.1

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

Witness: K. Culbert

UTILITY RATE BASE
2017 FORECAST YEAR

Line No.		Col. 1 2017 Forecast Year Excl. CIS & Customer Care	Col. 2 2017 Forecast Year CIS & Customer Care	Col. 3 Total 2017 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	8,686.6	127.1	8,813.7
2.	Accumulated depreciation	(3,258.4)	(107.4)	(3,365.8)
3.	Net property, plant, and equipment	5,428.2	19.7	5,447.9
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	40.0	-	40.0
11.	Total Working Capital	288.7	-	288.7
12.	Utility Rate Base	5,716.9	19.7	5,736.6

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	403.5	(141.3)	262.2
2.	Distribution plant	7,865.4	(2,907.6)	4,957.8
3.	General plant	427.4	(210.5)	216.9
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	8,696.8	(3,259.9)	5,436.9
6.	Plant held for future use	1.7	(1.3)	0.4
7.	Sub- total	8,698.5	(3,261.2)	5,437.3
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	8,686.6	(3,258.4)	5,428.2

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	45.5	-	-	45.5	(1.0)	44.5	44.5
3.	Structures and improvements (452.00)	44.1	6.6	(0.5)	50.3	(0.1)	50.2	45.2
4.	Wells (453.00)	65.2	2.6	-	67.7	-	67.7	65.7
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	69.4	1.1	(0.1)	70.5	-	70.5	69.6
7.	Compressor equipment (456.00)	113.7	0.2	-	113.9	(0.5)	113.4	113.3
8.	Measuring and regulating equipment (457.00)	14.7	0.0	-	14.8	-	14.8	14.7
9.	Base pressure gas (458.00)	41.0	-	-	41.0	-	41.0	41.0
10.	Total	403.1	10.5	(0.6)	413.1	(1.5)	411.6	403.5

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(24.6)	(0.5)	-	-	-	(25.0)	-	(25.0)	(24.8)
3.	Structures and improvements (452.00)	(7.0)	(0.8)	-	0.5	-	(7.3)	0.1	(7.2)	(7.1)
4.	Wells (453.00)	(19.5)	(1.0)	(0.0)	-	-	(20.5)	-	(20.5)	(20.0)
5.	Well equipment (454.00)	(7.2)	(0.5)	-	-	-	(7.8)	-	(7.8)	(7.5)
6.	Field Lines (455.00)	(27.4)	(1.1)	(0.1)	0.1	-	(28.5)	-	(28.5)	(28.0)
7.	Compressor equipment (456.00)	(45.2)	(3.1)	(0.1)	-	-	(48.4)	0.2	(48.2)	(46.6)
8.	Measuring and regulating equipment (457.00)	(7.1)	(0.5)	(0.0)	-	-	(7.6)	-	(7.6)	(7.4)
9.	Total	(138.0)	(7.4)	(0.3)	0.6	-	(145.1)	0.3	(144.8)	(141.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	29.0	-	-	29.0	-	29.0	29.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	96.8	-	-	96.8	-	96.8	96.8
4.	Structures and improvements (472.00)	137.5	6.5	(0.4)	143.6	(0.3)	143.3	140.1
5.	Services, house reg & meter install. (473/474)	2,559.9	136.3	(22.6)	2,673.5	-	2,673.5	2,611.7
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.5
7.	Meters (478)	449.7	26.7	(13.5)	462.8	-	462.8	454.3
8.	Sub-total	3,275.5	169.6	(36.7)	3,408.4	(0.3)	3,408.0	3,334.4
9.	Mains (475)	3,912.2	177.6	(4.0)	4,085.8	(2.2)	4,083.6	3,987.3
10.	Measuring and regulating equip. (477)	531.0	33.3	(2.0)	562.2	(0.5)	561.7	543.7
11.	Sub-total	4,443.2	210.9	(6.1)	4,648.1	(2.7)	4,645.3	4,531.0
12.	Total	7,718.7	380.5	(42.7)	8,056.4	(3.1)	8,053.4	7,865.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2016	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2017	Regulatory Adjustment (Note 1)	Utility Balance Dec.2017	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(3.4)	(1.1)	-	-	-	(4.6)	-	(4.6)	(4.0)
2.	Structures and improvements (472.00)	(28.5)	(9.0)	-	0.4	0.3	(36.9)	0.2	(36.6)	(32.4)
3.	Services, house reg & meter install. (473/474)	(1,040.1)	(64.4)	19.3	22.6	12.7	(1,049.9)	-	(1,049.9)	(1,044.2)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.0)	-	(2.0)	(2.0)
5.	Meters (478)	(209.7)	(41.8)	-	13.5	-	(238.0)	-	(238.0)	(223.7)
6.	Mains (475)	(1,355.8)	(104.2)	34.0	4.0	2.2	(1,419.8)	1.9	(1,417.9)	(1,383.0)
7.	Measuring and regulating equip. (477)	(214.2)	(11.7)	0.2	2.0	-	(223.7)	0.5	(223.1)	(218.3)
8.	Total	(2,853.7)	(232.3)	53.4	42.7	15.2	(2,974.7)	2.7	(2,972.1)	(2,907.6)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	17.3	0.3	-	17.6	(0.2) [1]	17.4	17.1
2.	Office furniture and equipment (483.00)	34.1	4.4	(1.0)	37.4	-	37.4	34.6
3.	Transportation equipment (484.00)	56.9	3.7	(0.9)	59.7	(0.1) [1]	59.6	57.2
4.	NGV conversion kits (484.01)	8.2	0.1	(0.3)	8.0	-	8.0	8.1
5.	Heavy work equipment (485.00)	24.3	1.3	(0.3)	25.3	-	25.3	24.5
6.	Tools and work equipment (486.00)	39.8	1.5	(1.1)	40.2	-	40.2	39.7
7.	Rental equipment (487.70)	5.2	1.4	(0.0)	6.6	-	6.6	5.5
8.	NGV rental compressors (487.80)	9.0	2.2	(0.3)	11.0	-	11.0	9.4
9.	NGV cylinders (484.02 and 487.90)	3.9	0.6	(0.0)	4.4	-	4.4	4.0
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	35.2	8.2	(6.9)	36.5	-	36.5	33.8
12.	Software Aquired/Developed (491.00)	125.4	22.8	(31.2)	116.9	-	116.9	119.0
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	70.6	-	-	70.6	-	70.6	70.6
14.	Total	560.8	46.4	(42.0)	565.3	(127.4)	437.9	427.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2017 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2017 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(8.3)	(1.1)	-	-	(9.4)	0.2 [1]	(9.3)	(8.7)
2.	Office furniture and equipment (483.00)	(14.5)	(3.4)	1.0	-	(16.8)	-	(16.8)	(15.6)
3.	Transportation equipment (484.00)	(28.7)	(6.0)	0.9	-	(33.8)	0.1 [1]	(33.7)	(31.2)
4.	NGV conversion kits (484.01)	(6.7)	(0.7)	0.3	-	(7.1)	-	(7.1)	(6.9)
5.	Heavy work equipment (485.00)	(9.8)	(0.9)	0.3	-	(10.4)	-	(10.4)	(10.1)
6.	Tools and work equipment (486.00)	(17.3)	(1.6)	1.1	-	(17.8)	-	(17.8)	(17.6)
7.	Rental equipment (487.70)	(1.0)	(0.0)	0.0	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.9)	(0.8)	0.3	-	(3.4)	-	(3.4)	(3.2)
9.	NGV cylinders (484.02 and 487.90)	(3.1)	(0.4)	0.0	-	(3.5)	-	(3.5)	(3.3)
10.	Communication structures & equip. (488)	(2.2)	(0.4)	-	-	(2.6)	-	(2.6)	(2.4)
11.	Computer equipment (490.00)	(32.7)	(12.4)	6.9	-	(38.2)	-	(38.2)	(35.5)
12.	Software Aquired/Developed (491.00)	(67.1)	(27.1)	31.2	-	(62.9)	-	(62.9)	(65.2)
13.	CIS (491.00)	(92.2)	(12.7)	-	-	(104.9)	104.9 [2]	-	-
14	WAMS (489.00)	(6.4)	(7.1)	-	-	(13.4)	-	(13.4)	(9.9)
15	Total	(292.8)	(74.5)	42.0	-	(325.4)	105.1	(220.3)	(210.5)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

Witness: K. Culbert

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: K. Culbert

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)
2.	Total	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)

Witness: K. Culbert

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 FORECAST YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	34.1	-	(65.6)	0.6	381.4	40.0	391.9
2.	January 31	1.4	34.2	-	(65.1)	0.7	227.6	40.0	238.8
3.	February	1.4	34.3	-	(64.3)	0.4	105.1	40.0	116.9
4.	March	1.4	34.4	-	(64.3)	0.5	36.8	40.0	48.8
5.	April	1.4	34.5	-	(64.2)	1.0	48.3	40.0	61.0
6.	May	1.4	34.5	-	(64.2)	0.9	116.4	40.0	129.0
7.	June	1.4	34.6	-	(64.1)	0.9	203.5	40.0	216.3
8.	July	1.3	34.7	-	(64.1)	0.8	299.5	40.0	312.2
9.	August	1.3	34.8	-	(64.1)	2.2	396.1	40.0	410.3
10.	September	1.3	34.9	-	(64.8)	1.7	481.3	40.0	494.4
11.	October	1.3	34.9	-	(65.2)	1.1	524.4	40.0	536.5
12.	November	1.3	35.0	-	(65.9)	0.7	495.5	40.0	506.6
13.	December	1.3	35.1	-	(65.1)	0.6	380.0	40.0	391.9
14.	Avg. of monthly avgs.	1.4	34.6	-	(64.6)	1.0	276.3	40.0	288.7

Witness: K. Culbert

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2017 FORECAST YEAR

		Col. 1	Col. 2	Col. 3
Line No.		Disbursements	Net Lag-Days	Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,647.2	8.8	39.7
2.	Items not subject to working cash allowance (Note 1)	(14.7)		
3.	Gas costs charged to operations	1,632.5		
4.	Operation and Maintenance	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	(4.4)	(4.1)
9.	Sub-total			35.6
10.	Storage costs	8.4	64.9	1.5
11.	Storage municipal and capital taxes	1.4	29.4	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			2.8
14.	Total working cash allowance			40.0

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

Witness: K. Culbert

UTILITY RATE BASE
2018 FORECAST YEAR

Line No.		Col. 1 2018 Forecast Year Excl. CIS & Customer Care	Col. 2 2018 Forecast Year CIS & Customer Care	Col. 3 Total 2018 Forecast Year
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,042.2	127.1	9,169.3
2.	Accumulated depreciation	(3,431.7)	(120.1)	(3,551.8)
3.	Net property, plant, and equipment	5,610.5	7.0	5,617.5
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3
10.	Working cash allowance	39.9	-	39.9
11.	Total Working Capital	288.6	-	288.6
12.	Utility Rate Base	5,899.1	7.0	5,906.1

Witness: K. Culbert

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	413.4	(148.4)	265.0
2.	Distribution plant	8,206.6	(3,054.3)	5,152.3
3.	General plant	431.9	(229.9)	202.0
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	9,052.4	(3,433.1)	5,619.3
6.	Plant held for future use	1.7	(1.4)	0.3
7.	Sub- total	9,054.1	(3,434.5)	5,619.6
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	9,042.2	(3,431.7)	5,610.5

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-
2.	Land and gas storage rights (450/451)	45.5	-	-	45.5	(1.0)	44.5	44.5
3.	Structures and improvements (452.00)	50.3	6.6	(0.5)	56.4	(0.1)	56.3	51.3
4.	Wells (453.00)	67.7	2.6	-	70.3	-	70.3	68.2
5.	Well equipment (454.00)	9.6	-	-	9.6	-	9.6	9.6
6.	Field Lines (455.00)	70.5	1.1	(0.1)	71.5	-	71.5	70.7
7.	Compressor equipment (456.00)	113.9	0.2	-	114.1	(0.5)	113.7	113.5
8.	Measuring and regulating equipment (457.00)	14.8	0.0	-	14.8	-	14.8	14.8
9.	Base pressure gas (458.00)	41.0	-	-	41.0	-	41.0	41.0
10.	Total	413.1	10.5	(0.6)	423.0	(1.5)	421.5	413.4

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	-	-	-	-	-	-	-	-	-
2.	Land and gas storage rights (451.00)	(25.0)	(0.5)	-	-	-	(25.5)	-	(25.5)	(25.3)
3.	Structures and improvements (452.00)	(7.3)	(0.9)	-	0.5	-	(7.7)	0.1	(7.6)	(7.4)
4.	Wells (453.00)	(20.5)	(1.1)	(0.0)	-	-	(21.6)	-	(21.6)	(21.0)
5.	Well equipment (454.00)	(7.8)	(0.5)	-	-	-	(8.3)	-	(8.3)	(8.0)
6.	Field Lines (455.00)	(28.5)	(1.1)	(0.0)	0.1	-	(29.6)	-	(29.6)	(29.1)
7.	Compressor equipment (456.00)	(48.4)	(3.1)	(0.0)	-	-	(51.5)	0.2	(51.3)	(49.8)
8.	Measuring and regulating equipment (457.00)	(7.6)	(0.5)	-	-	-	(8.1)	-	(8.0)	(7.8)
9.	Total	(145.1)	(7.6)	(0.1)	0.6	-	(152.2)	0.3	(151.9)	(148.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witness: K. Culbert

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	29.0	-	-	29.0	-	29.0	29.0
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	96.8	-	-	96.8	-	96.8	96.8
4.	Structures and improvements (472.00)	143.6	6.5	(0.4)	149.7	(0.3)	149.4	146.2
5.	Services, house reg & meter install. (473/474)	2,673.5	136.3	(22.6)	2,787.2	-	2,787.2	2,725.3
6.	NGV station compressors (476)	2.6	0.1	(0.1)	2.6	-	2.6	2.5
7.	Meters (478)	462.8	26.7	(13.5)	476.0	-	476.0	467.4
8.	Sub-total	3,408.4	169.6	(36.7)	3,541.2	(0.3)	3,540.9	3,467.3
9.	Mains (475)	4,085.8	182.4	(4.0)	4,264.2	(2.2)	4,262.0	4,164.3
10.	Measuring and regulating equip. (477)	562.2	33.3	(2.0)	593.5	(0.5)	592.9	575.0
11.	Sub-total	4,648.1	215.7	(6.1)	4,857.7	(2.7)	4,854.9	4,739.3
12.	Total	8,056.4	385.2	(42.7)	8,398.9	(3.1)	8,395.8	8,206.6

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(4.6)	(1.1)	-	-	-	(5.7)	-	(5.7)	(5.1)
2.	Structures and improvements (472.00)	(36.9)	(9.5)	-	0.4	0.3	(45.7)	0.3	(45.5)	(41.0)
3.	Services, house reg & meter install. (473/474)	(1,049.9)	(67.2)	5.9	22.6	12.7	(1,075.9)	-	(1,075.9)	(1,063.2)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	0.1	-	(2.1)	-	(2.1)	(2.0)
5.	Meters (478)	(238.0)	(43.1)	-	13.5	-	(267.5)	-	(267.5)	(252.7)
6.	Mains (475)	(1,419.8)	(108.4)	11.6	4.0	2.2	(1,510.4)	2.0	(1,508.4)	(1,462.1)
7.	Measuring and regulating equip. (477)	(223.7)	(12.3)	0.0	2.0	-	(233.9)	0.6	(233.3)	(228.2)
8.	Total	(2,974.7)	(241.8)	17.5	42.7	15.2	(3,141.1)	2.8	(3,138.4)	(3,054.3)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	17.6	0.3	-	17.9	(0.2) [1]	17.7	17.4
2.	Office furniture and equipment (483.00)	37.4	4.4	(1.0)	40.8	-	40.8	38.0
3.	Transportation equipment (484.00)	59.7	3.7	(0.9)	62.4	(0.1) [1]	62.4	60.0
4.	NGV conversion kits (484.01)	8.0	0.1	(0.3)	7.9	-	7.9	7.9
5.	Heavy work equipment (485.00)	25.3	1.3	(0.3)	26.4	-	26.4	25.5
6.	Tools and work equipment (486.00)	40.2	1.5	(1.1)	40.6	-	40.6	40.1
7.	Rental equipment (487.70)	6.6	1.4	(0.0)	8.0	-	8.0	6.9
8.	NGV rental compressors (487.80)	11.0	2.2	(0.3)	12.9	-	12.9	11.4
9.	NGV cylinders (484.02 and 487.90)	4.4	0.6	(0.0)	5.0	-	5.0	4.5
10.	Communication structures & equip. (488)	3.9	-	-	3.9	-	3.9	3.9
11.	Computer equipment (490.00)	36.5	8.2	(6.9)	37.8	-	37.8	35.1
12.	Software Aquired/Developed (491.00)	116.9	22.8	(31.2)	108.5	-	108.5	110.6
13.	CIS (491.00)	127.1	-	-	127.1	(127.1) [2]	-	-
14	WAMS (489.00)	70.6	-	-	70.6	-	70.6	70.6
15	Total	565.3	46.4	(42.0)	569.7	(127.4)	442.4	431.9

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

Witness: K. Culbert

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2018 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2018 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(9.4)	(1.1)	-	-	(10.6)	0.2 [1]	(10.4)	(9.8)
2.	Office furniture and equipment (483.00)	(16.8)	(3.7)	1.0	-	(19.4)	-	(19.4)	(18.1)
3.	Transportation equipment (484.00)	(33.8)	(6.3)	0.9	-	(39.2)	0.1 [1]	(39.1)	(36.4)
4.	NGV conversion kits (484.01)	(7.1)	(0.7)	0.3	-	(7.6)	-	(7.6)	(7.4)
5.	Heavy work equipment (485.00)	(10.4)	(0.9)	0.3	-	(11.1)	-	(11.1)	(10.7)
6.	Tools and work equipment (486.00)	(17.8)	(1.6)	1.1	-	(18.4)	-	(18.4)	(18.1)
7.	Rental equipment (487.70)	(1.0)	(0.1)	0.0	-	(1.1)	-	(1.1)	(1.1)
8.	NGV rental compressors (487.80)	(3.4)	(0.9)	0.3	-	(4.1)	-	(4.1)	(3.7)
9.	NGV cylinders (484.02 and 487.90)	(3.5)	(0.5)	0.0	-	(3.9)	-	(3.9)	(3.7)
10.	Communication structures & equip. (488)	(2.6)	(0.4)	-	-	(3.0)	-	(3.0)	(2.8)
11.	Computer equipment (490.00)	(38.2)	(12.8)	6.9	-	(44.1)	-	(44.1)	(41.2)
12.	Software Aquired/Developed (491.00)	(62.9)	(24.7)	31.2	-	(56.4)	-	(56.4)	(59.8)
13.	CIS (491.00)	(104.9)	(12.7)	-	-	(117.6)	117.6 [2]	-	-
14	WAMS (489.00)	(13.4)	(7.1)	-	-	(20.5)	-	(20.5)	(16.9)
15	Total	(325.4)	(73.5)	42.0	-	(356.9)	117.8	(239.1)	(229.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.
Note 2: Separation of previous approved CC/CIS amounts enabling an all other Utility deficiency/rate impact calculation. (Ex.D1.T12.S1)

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

Witness: K. Culbert

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Line No.		Opening Balance Dec.2017	Additions	Retirements	Closing Balance Dec.2018	Regulatory Adjustment	Utility Balance Dec.2018	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)
2.	Total	(1.3)	(0.0)	-	-	(1.4)	-	(1.4)	(1.4)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 FORECAST YEAR

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	34.1	-	(65.6)	0.6	381.4	39.9	391.8
2.	January 31	1.4	34.2	-	(65.1)	0.7	227.6	39.9	238.7
3.	February	1.4	34.3	-	(64.3)	0.4	105.1	39.9	116.8
4.	March	1.4	34.4	-	(64.3)	0.5	36.8	39.9	48.7
5.	April	1.4	34.5	-	(64.2)	1.0	48.3	39.9	60.9
6.	May	1.4	34.5	-	(64.2)	0.9	116.4	39.9	128.9
7.	June	1.4	34.6	-	(64.1)	0.9	203.5	39.9	216.2
8.	July	1.3	34.7	-	(64.1)	0.8	299.5	39.9	312.1
9.	August	1.3	34.8	-	(64.1)	2.2	396.1	39.9	410.2
10.	September	1.3	34.9	-	(64.8)	1.7	481.3	39.9	494.3
11.	October	1.3	34.9	-	(65.2)	1.1	524.4	39.9	536.4
12.	November	1.3	35.0	-	(65.9)	0.7	495.5	39.9	506.5
13.	December	1.3	35.1	-	(65.1)	0.6	380.0	39.9	391.8
14.	Avg. of monthly avgs.	1.4	34.6	-	(64.6)	1.0	276.3	39.9	288.6

Witness: K. Culbert

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2018 FORECAST YEAR

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,647.2	8.8	39.7
2.	Items not subject to working cash allowance (Note 1)	(14.7)		
3.	Gas costs charged to operations	1,632.5		
4.	Operation and Maintenance	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	(4.4)	(4.2)
9.	Sub-total			35.5
10.	Storage costs	8.4	64.9	1.5
11.	Storage municipal and capital taxes	1.4	29.4	0.1
12.	Sub-total			1.6
13.	Harmonized Sales Tax			2.8
14.	Total working cash allowance			39.9

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

Witness: K. Culbert