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April 25, 2019

BY EMAIL, COURIER & RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli,

Re: EB-2018-0305 Enbridge Gas Inc. ("Enbridge Gas") – 2019 Rate Application Interrogatory Responses

In accordance with the Ontario Energy Board's (the "Board") Procudural Order No. 3, enclosed please find the interrogatory repsonses of Enbridge Gas.

Also enclosed please find the following updates to the evidence:

Exhibit	Addendum / Correction
Exhibit B1, Tab 1, Schedule 1, Appendix A	Appendix A has been updated to include the Board Approved RNG Accounting Order
Exhibit B1, Tab 1, Schedule 1, Appendix H, page 6	Section 25 has been updated to include the third new definition in the Community Expansion framework which would enable projects to qualify for additional distribution revenue
Exhibit B1, Tab 2, Schedule 1, page 16, Table 6, line 1	2013 Board-Approved' has been corrected to read '2018 Board-Approved'
Exhibit B1, Tab 2, Schedule 1, page 17, Table 6, line 7	Line 7 has been corrected to include 'EGD' rate zone
Exhibit B1, Tab 2, Schedule 1, page 28, line 14	Line 7 has been corrected to show 'incremental revenue requirement of $5.3 million'
Exhibit B1, Tab 2, Schedule 1, page 29, Table 10, line 3,5,6	The Revenue Requirement for Kingsville has been corrected
Exhibit B1, Tab 2, Schedule 1, page 31, Table 11, line 3,5,6	The Revenue Requirement for Kingsville has been corrected
Exhibit B1, Tab 2, Schedule 1, Appendix E, page 3	The Revenue Requirement for Kingsville has been corrected
Exhibit C1, Tab 1, Schedule 1, page 43, Table 3	The label in Table 3 has been updated to show Union and EGD

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager
Regulatory Applications

cc: EB-2018-0305 Intervenors
Crawford Smith, Lax O'Sullivan Lisus Gottlieb

ACCOUNTING TREATMENT FOR A RNG INJECTION SERVICE VARIANCE ACCOUNT ("RNGISVA") – EGD RATE ZONE

The purpose of the RNGISVA is to record the annual revenue sufficiency/deficiency related to the provision of RNG Injection Services to RNG producers. The calculation of any annual revenue sufficiency/deficiency will be calculated as the difference between actual revenues generated under Rate 401 (RNG Injection Service), and the actual revenue requirement impact of the costs incurred (on a fully allocated basis) to provide those sevices. In order to ensure that ratepayers are not harmed by potential default of Rate 401 customers, the annual revenue sufficiency/deficiency calclulation will not include any impacts of contract default by RNG injection services customers.

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

<u>Accounting Entries</u>

1. To record the annual revenue sufficiency/deficiency:

Debit/Credit:	RNGISVA	(Account 179. ___)
Credit/Debit:	Operating Revenue	(Account 300. 000)

To record the annual revenue sufficiency/deficiency in relation to providing the RNG Injection Service to RNG producers.

2. Interest accrual:

Debit/Credit:	Interest on RNGISVA	(Account 179. ___)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the RNGISVA using the Board approved EB-2006-0117 interest rate methodology.

EGD RATE ZONE - 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 and community 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, Method for Economic Feasibility Assessment, and Procedure for Capital Expenditure Approval. It has been expanded to include key elements of the Company policy under the Community Expansion framework as approved by the Board in EB-2016-0004 dated November 17, 2016. The new framework applies to all qualifying Community Expansion ("CE") Projects and Small Main Extension ("SME") projects.

3. The evidence also provides more detail on the cost estimation refinement utilized for residential infill customers to address observed variability in costs. The refined approach improves the accuracy of economic feasibility assessment and fulfills the commitment made as part of the Settlement for the disposition of 2017 deferral and variance accounts (ESM Application, EB-2018-0131, page 8).

Customer Connection Policy

4. The Company uses a portfolio approach to manage its 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 4 of this evidence.

5. The Company manages both its portfolio approaches to achieve a Profitability Index ("PI") of greater than 1.0 as required by the Board under EBO 188.

6. 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.

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

Customer Contribution and Refund Policy

8. 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 required level. Harmonized Sales Tax ("HST") is added to contribution payments.

9. The feasibility of residential customers connecting to existing mains is based on customers' "Revenue Allowance[1]" and "Service costs[2]", which are individually estimated for these services. The amount of Service Cost in excess of the Revenue Allowance is the CIAC amount which is recovered from customers before service installation. This approach has replaced the previous 20 metre rule, whereby standard residential services were deemed feasible to a certain threshold of length (i.e., 20 metres) or customers would pay a CIAC

[1] "Revenue Allowance" is driven by customers' consumption and represents the amount of capital Enbridge can invest to achieve the required feasibility threshold (i.e. PI of 1.0). The revenue allowance is determined by taking the present value of a customer's future revenue over 40 years.
[2] "Service Cost" is the estimated capital cost for each infill service connection. Methods of estimation are described at paragraph 18.

amount at a rate of $32 for each additional metre beyond this threshold. The previous approach relied on the assumption of consistent or like circumstances for standard residential service connections, which is no longer appropriate.

10. 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.

11. Refunds of CIAC may be requested by customers 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 the revised contribution amount and the actual contribution paid by customers is the total amount to be refunded to original customers. Refunds are made based on the proportionate contribution of customers.

12. Furthermore, these refunds are made only for the specific piece of main put into service; no refunds are payable for customers added downstream of the specific 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.

13. 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). Similar to system expansions, refunds for large volume customers will be evaluated subject to customer request.

System Expansion Portfolios – Accountability

14. Investment Portfolio: The Company evaluates all system expansion projects in a test year and ensures they are designed to achieve a portfolio PI of at least 1.1. All new customers attaching to new and existing mains are included in this portfolio.

15. 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.

Estimating Inputs for Economic Feasibility Assessment

16. This section provides the method used to determine the parameters that make up the economic feasibility assessment. It includes capital cost, O&M expenses, and distribution revenues associated with a system expansion project. These inputs are discounted at the Utility's Weighted Average Cost of Capital ("WACC") to carry out the DCF analysis which measures Economic Feasibility of a project based on NPV and PI.

Capital Cost Estimation

17. The Company uses various approaches for estimating capital cost for different types of projects. The objective is to derive estimates that are closely aligned to costs that are reflective of the unique parameters of each project, and those cost differences are typically delineated by geographic area.

18. The following is a summary of various estimation techniques and the project types to which they are applied:
    - For new subdivisions where Joint Utility Trenching ("JUT") is often used to construct natural gas infrastructure, unit rates prescribed in the underlying contracts are used for estimating capital cost for mains and services.
    - For subdivisions where JUT is not an option, or for commercial and industrial connections, field estimates are used for capital costing.
    - For residential infill services, capital cost is based on a regionally-specific estimate that relies on historical actual data of similar services installed. It can also be a specific field estimate where no historical data are available that is representative of the geographic area. In instances where known geographical/geological factors (e.g. rock, depth of main) have influenced capital costs, Enbridge will utilize pricing for those factors to inform the estimate.
    - For large volume connections (i.e., above 340 000 m^3 annual consumption), field estimates are used to estimate mains and service cost.

19. 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 Authorization for Expenditure ("AFE").

20. An incremental overhead allowance is added to the cost of mains and services and is incorporated in the feasibility analysis of all projects.

Consumption and Revenue

21. For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split or two-story).

22. The Capital Project Feasibility ("CAPF") program calculates customer revenue based on consumption levels input by the Customer Connections Representative ("CCR").

23. 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.

24. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand.

25. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board Approved revenue rates.

26. In its Community Expansion framework, the Board accepted the following new definitions which would enable projects to qualify for additional distribution revenue:
    - Community Expansion Project: A natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers already exist, for which economic feasibility guidelines derive a Profitability Index ("PI") of less than 1.0
    - Short Main Extension Projects: All other forms of distribution system expansion which provide first time natural gas system access to customers where fewer than 50 potential customers in homes and business already exist and where the PI for the project is less than 1.0.
    - A natural gas system expansion project meeting either of the two definitions above that /u requires the SES and potentially other financing mechanisms in order for project economics to attain a PI of 1.0.

27. Qualifying Community Expansion (“CE”) projects are assessed for feasibility by including a System Expansion Surcharge (“SES”) of $0.23 per m^3 in addition to the distribution revenue and an Incremental Tax Equivalent[3] (“ITE”).

28. The SES would be paid by all customers located in areas served by designated CE projects for up to 40 years or until the projects achieves a PI of 1.0. The ITE mechanism will remain applicable for 10 years.

Customer Attachment and Revenue Horizon

29. The maximum customer attachment horizon for residential, commercial and industrial connections with annual consumption below 340 000 m^3 is 10 years. The revenue horizon is 40 years from the in-service date of the initial mainline.

30. For large volume customers, the maximum customer attachment horizon is 10 years. The maximum revenue horizon is 20 years from the customers' initial service date.

31. A project specific revenue horizon is used when the project life cycle is deemed shorter than 20 years.

Marginal Operating and Maintenance (“O&M”) Expenses

32. The Company’s incremental operating and maintenance (“O&M”) cost is based on an annual study that is aligned with cost allocation principles and is included in assessing project feasibility.

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[3] Incremental Tax Equivalent (“ITE”) is a mechanism to collect municipal contributions to assist with project feasibility.

Procedure for Capital Expenditure Approval

33. 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 Customer Connections Representative ("CCR"), who identifies potential new customers. The CCR will assess the required amount of plant additions to provide service and will initiate an AFE for approval.

34. A feasibility assessment is required to be attached to an AFE as part of the approval process. Feasibility assessment is done based on the estimated revenue and benefits of connecting new customers against the total cost of attaching and serving them. The Capital Project Feasibility ("CAPF") program is an online IT tool used for evaluating all projects except for residential infills connections and Large Volume projects. Residential infill services are assessed using a Non-Gas Payment ("NGP") tool by the customer connection group. All Large-volume projects are separately evaluated by the Investment Review group using Excel based feasibility tools.

35. CCRs provide inputs for the CAPF tool, which include estimates of capital cost, customer additions and timing, and annual consumptions of new customers. The Investment Review group uses Excel based feasibility tools for assessing large-volume and more complex projects with inputs from the Special Projects and Key Accounts groups.

36. All AFEs are approved by the appropriate level of authority including managers, directors, VPs and President as set out in the workflows based on capital approval authority. The Capital Management group in Finance provides overall governance over the AFE approval process. This group also ensures compliance with the Company's Connection Policies.

ENBRIDGE GAS INC. 2019 RATE APPLICATION

INCREMENTAL CAPITAL MODULE

This evidence discusses Enbridge Gas's request for incremental capital module ("ICM") funding in support of capital investment needs that are not funded through existing rates. The Board approved the use of an ICM to fund incremental capital during Enbridge Gas's 2019-2023 deferred rebasing period as part of the MAADs Decision[1].

The ICM evidence is organized as follows:

1. Capital Planning Overview
2. Eligibility for Incremental Capital
    2.1 Materiality
    2.2 Need
    2.3 Prudence
3. Customer Consultation
4. Calculation of Revenue Requirement
5. Cost Allocation
6. ICM Unit Rates
7. ICM Bill Impacts

[1] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018. The Decision and Order was later amended by the Board on September 17, 2018 with no material changes.

1. CAPITAL PLANNING OVERVIEW

In support of the 2019 ICM request, Enbridge Gas is filing a Utility System Plan[2] ("USP") which includes an Asset Management Plan ("AMP") for each of the EGD and Union rate zones. Each AMP identifies how Enbridge Gas plans, manages and develops the distribution, transmission, and storage systems for each of the EGD and Union rate zones, and determines the capital investment requirement while balancing risk, performance and cost.[3] The USP includes information about the addition of assets to meet customer needs and maintenance requirements to ensure the ongoing safety and security of supply for Enbridge Gas's customers, while satisfying applicable regulatory requirements and compliance obligations. The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to resolve degraded condition or performance of an existing asset. In either case, the process to create a new asset is the same.

Through the budgeting process, the risks that each project is mitigating are re-evaluated and endorsed.

As there are finite resources to complete capital projects, projects are selected for the AMP on the basis of their relative priority. All projects are evaluated and prioritized/optimized to ensure that capital resources are employed to address the highest priority items across all asset categories.

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[2] The USP for Enbridge Gas is filed at Exhibit C1, Tab 1, Schedule 1.
[3] The AMPs for Enbridge Gas are filed at Exhibit C1, Tab 2, Schedule 1 and Exhibit C1, Tab 3, Schedule 1.

Enbridge Gas's methodology for project prioritization/optimization considers risk, customer input and preferences, resource availability and asset portfolio strategies. More details on the project prioritization/optimization can be found in each of the EGD and Union AMPs.

The historical and forecast capital investments[4] by category for the 2014 to 2023 period are shown in Table 1 for the EGD rate zone and Table 2 for the Union rate zones. These capital investments will allow Enbridge Gas to continue to meet customer needs and ensure safe and reliable delivery of natural gas to customers.

[4] In-service capital for the year.

Table 1
Capital Expenditures by category (2014-2023) – EGD Rate Zone ($ Millions)

Line No.	Category	(a) **2014 Actual**	(b) **2015 Actual**	(c) **2016 Actual**	(d) **2017 Actual**	(e) **2018 Forecast**
1	General Plant	69.0	91.9	82.6	48.1	42.9
2	System Access[5]	112.8	105.2	118.3	109.3	118.5
3	System Renewal	96.5	102.7	109.1	102.2	112.0
4	System Service	190.5	569.6	127.1	20.2	17.9
5	Total Overhead	141.3	145.9	156.4	148.1	146.5
6	**Total - EGD Rate Zone**	**610.1**	**1,015.3**	**593.5**	**427.8**	**437.9**

Line No.	Category	(f) **2019 Budget**	(g) **2020 Budget**	(h) **2021 Budget**	(i) **2022 Budget**	(j) **2023 Budget**
1	General Plant	52.4	48.8	59.2	53.3	39.4
2	System Access[5]	111.3	119.4	124.3	122.4	122.5
3	System Renewal	152.3	198.1	146.4	191.5	147.7
4	System Service	23.5	17.1	8.5	8.5	14.3
5	Total Overhead	142.1	163.2	152.2	161.7	164.8
6	**Total - EGD Rate Zone**	**481.7**	**546.6**	**490.6**	**537.5**	**488.8**

[5] System Access capital presented here does not reflect Community Expansion.

Table 2
Capital Expenditures by category (2014-2023) – Union Rate Zones ($ Millions)

Line No.	Category	(a) **2014 Actual**	(b) **2015 Actual**	(c) **2016 Actual**	(d) **2017 Actual**	(e) **2018 Forecast**
1	General Plant	56.5	51.4	44.8	42.8	47.8
2	System Access[6]	83.9	107.8	105.6	96.2	100.8
3	System Renewal	83.8	73.0	76.3	87.6	107.5
4	System Service	190.4	391.5	734.3	412.2	215.3
5	Total Overhead	68.2	71.5	77.2	78.6	77.2
6	**Total - Union Rate Zones**	**482.9**	**695.2**	**1,038.2**	**717.5**	**548.6**

Line No.	Category	(f) **2019 Budget**	(g) **2020 Budget**	(h) **2021 Budget**	(i) **2022 Budget**	(j) **2023 Budget**
1	General Plant	55.2	60.1	65.8	61.4	63.5
2	System Access[6]	107.9	96.3	91.5	92.9	97.3
3	System Renewal	97.5	202.7	245.1	115.4	209.2
4	System Service	184.6	156.8	47.5	72.3	89.6
5	Total Overhead	82.5	80.4	80.0	78.2	82.9
6	**Total - Union Rate Zones**	**527.5**	**596.3**	**529.9**	**420.3**	**542.4**

[6] System Access capital presented here does not reflect Community Expansion.

General Plant

General plant investments are modifications, replacements or additions to Enbridge Gas's assets that are not part of its commodity-carrying system including land and buildings, tools and equipment, fleet vehicles and electronic devices and software used to support day to day business and operations activities.

The historical and forecast general plant capital expenditures are presented in Appendix A, Table A for EGD rate zone and Table B for Union rate zones.

System Access

System access investments are additions and modifications (including asset relocation) to Enbridge Gas's distribution system that the utility is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution and transmission systems.

EGD rate zone system access capital expenditures are mainly driven by Customer Growth, Natural Gas for Vehicles (NGV) and third party driven rebillable relocation projects. Similarly, Union rate zones system access capital expenditures are driven by Customer Growth, Compressed Natural Gas and Municipal Replacement.

The historical and forecast system access capital expenditures are presented in Appendix A, Table C for EGD rate zone and Table D for Union rate zones.

System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enbridge Gas's system to provide customers with natural gas services.

EGD rate zone system renewal capital expenditures are mainly driven by Main Replacements, Meter Exchanges/Replacements, Compressor Equipment, Regulator Refits and Service Relays. Union rate zones system renewal capital expenditures are mainly driven by Stations Replacements, Vintage Pipeline Replacement, the Integrity Management Program, Compression Equipment, and the Meter Exchange Program.

The historical and forecast system renewal capital expenditures are presented in Appendix A, Table E for EGD rate zone and Table F for Union rate zones.

System Service

System service investments are modifications to Enbridge Gas's distribution system to ensure the system continues to meet distributor operational objectives.

EGD rate zone system service capital expenditures are mainly driven by reinforcement projects and integrity initiatives. Union rate zones system service capital expenditures are mainly driven by transmission and distribution system growth, reinforcements, and class location initiatives. The historical and forecast system service capital expenditures are presented in Appendix A, Table G for EGD rate zone and Table H for Union rate zones.

2. ELIGIBILITY FOR ICM CAPITAL

In the MAADs Decision, the Board confirmed the availability of ICM funding for Enbridge Gas.[7] As set out in section 4.1.5 of the "Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219", to be eligible for recovery, capital projects must meet the following criteria: materiality, need and prudence. Each of these criteria is described below in relation to Enbridge Gas's ICM funding request for 2019.

2.1 MATERIALITY

Materiality Threshold Test

As defined by the Board, "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as

[7] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.30-34.

defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing."[8]

The Board determined the formula to be used to calculate the materiality threshold as follows:

$$\textbf{Threshold Value} = 1 + [(RB/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^{n-1} + 10\%$$

Where:

RB	= Rate base included in base rates ($)
d	= Depreciation expense included in base rates ($)
g	= Growth factor (%)
PCI	= Price cap index (%)
n	= Number of years since rebasing

The Board's ICM materiality threshold calculation results in a 2019 threshold value of $468.5 million for the EGD rate zone and $375.2 million for the combined Union rate zones. The materiality threshold establishes the minimum capital expenditures a utility must fund through base rates. The maximum incremental capital investment eligible for ICM funding is the amount of capital expenditures in the year in excess of the threshold value. The calculation of the ICM materiality threshold value for EGD and Union rate zones is provided in Table 3 below.

[8] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

Table 3
ICM Threshold Capital Expenditure Calculation by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	Year	2019	2019
2	Base Year	2018	2013
3	Number of Years since rebasing (n)	1	6
4	Price Cap Index (PCI) (%)	1.07%	0.72%
5	Growth Factor (g) (%)	1.04%	1.19%
6	Dead Band (%)	10%	10%
7	Rate Base (RB)	6,246	5,331[9]
8	Depreciation (d)	305	239[10]
9	Threshold Value (%)	153%	157%
10	Threshold Value	468.5	375.2

A description of the Price Cap Index, growth factor, and rate base and depreciation amounts used in the threshold calculation are provided below.

Price Cap Index

The Board’s threshold value calculation uses PCI to recognize the increase in revenue generated through annual rate increases in a price cap plan that could be used toward capital investment. The Board’s calculation uses a current year PCI, which does not recognize the actual change in rates experienced over a multi-year price cap IR term and can result in a threshold value that does

[9] As per the MAADs Decision, the rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during Union’s 2014-2018 IRM term are added to the 2013 Board approved rate base and depreciation.
[10] *Ibid.*

not represent the actual revenue increase during that period. To reflect the rate increases during the price cap IR term, Enbridge Gas proposes to use a simple average of the actual annual PCI that has been used to increase rates during the price cap IR term since its last rebasing. The average PCI more accurately reflects the impact PCI has had on rates and revenue since the base year (2013 rates for Union and 2018 rates for EGD) than the use of the current year PCI. The use of the average PCI also reduces the year-to-year fluctuations in the threshold value that would occur by using the current year PCI and helps the utility plan and prioritize capital investments through a more stable threshold value. This also aligns with customer preferences of a steady rate of investment, over a less predictable pace.

Accordingly, the PCI used for the EGD rate zone threshold calculation of 1.07% is the 2019 value since 2019 is the first year of its price cap plan. The PCI used for the Union rate zones threshold calculation of 0.72% is the average of the actual annual PCI used to increase rates during its price cap plan which began in 2014. The calculation of the PCI by rate zone is provided in Table 4 below.

Table 4
Price Cap Index by Rate Zone

Line No.	Year	EGD	Union
		(a)	(b)
1	2014	N/A	0.51%
2	2015	N/A	0.66%
3	2016	N/A	0.71%
4	2017	N/A	0.70%
5	2018	N/A	0.66%
6	2019	1.07%	1.07%
7	Average (1)	1.07%	0.72%

Note:
(1) 2019 for the EGD rate zone and 2014-2019 six-year average for the Union rate zones.

Growth Factor

The 2019 growth factor has been calculated by comparing the percentage difference in annual revenues between 2017 (the most recent complete year) and the approved base year[11] for each rate zone. The revenue amounts are calculated at the approved base year's rates.

To determine the 2017 revenue from general service rate classes, Enbridge Gas used the actual customer count and held the normalized average consumption/average use ("NAC/AU") per customer constant with the NAC/AU in base rates. If the NAC/AU is not held constant, then any

[11] 2018 for the EGD rate zone and 2013 for the Union rate zones.

change in NAC/AU would have to be offset by a proportionally similar rate adjustment to keep the revenue per customer constant. Both the EGD and Union rate zones have deferral accounts that record the revenue impact associated with the difference between the forecast normalized average use per customer embedded in rates and the actual normalized average use experienced during the year. By using the NAC/AU per customer and the rate that is in base rates to calculate 2017 revenue, the growth factor will account for both the actual general service revenue and the revenue amounts collected/refunded in the NAC/AU deferral account.

The use of the NAC/AU in base rates also normalizes the general service revenue for variability in weather during the year. Enbridge Gas assumes normal weather when developing all forward looking plans, including the gas supply plan, the AMP, and the annual budget and long range plan. Using a growth factor that compares revenues on a weather-normalized basis is therefore consistent with the development of the USP and corresponding AMP. Enbridge Gas recognizes the Board considered and did not change the approach of comparing weather-normalized revenues to weather-actual revenues in the EB-2014-0219 Supplemental Report.[12] The Board's explanation for not changing the approach was due to the high proportion of electric revenues from fixed charges that are non-weather sensitive. Enbridge Gas has a considerably higher proportion of volumetric charges that are weather sensitive for general service customers and calculating the

[12] EB-2014-0219Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016, p.14-15.

growth factor on weather-normalized general service revenues reduces the year-to-year fluctuations in the threshold value that would occur if it were to use weather-actual results.

Enbridge Gas calculated the 2017 revenue from contract rate class using weather-actual data, as contract-rate customers are generally less weather sensitive and have a higher proportion of fixed cost recovery as compared to general service customers. Table 5 below shows the calculation of the growth factor.

Table 5
Growth Factor by Rate Zone

Line No.	Particulars	($ millions)
		(a)
	EGD	
1	2018 Board-approved Distribution Revenues	1,225.1
2	2017 Distribution Revenues	1,212.5
3	Growth Factor	1.04%
	Union	
4	2017 Distribution Revenues[13]	968.1
5	2013 Board-approved Distribution Revenues[14]	924.0
6	Growth Factor (Annualized)	1.19%

A detailed calculation of the revenues underpinning the growth factor for each rate zone is filed as Appendix B.

[13] Includes regulated distribution and transmission revenues.
[14] *Ibid.*

Rate Base and Depreciation

The threshold calculation uses the rate base and depreciation expense last approved by the Board. Accordingly, the threshold value for the EGD rate zone is based on EGD's 2018 Board-approved rate base and depreciation.

Pursuant to the MAADs Decision, the threshold value for the Union rate zones is based on Union's 2013 Board-approved rate base and depreciation plus the 2019 forecast amount of rate base and depreciation associated with projects that were eligible for capital pass-through treatment and included in Union's base rates during Union's 2014-2018 IRM term.[15] The capital pass-through forecast revenue requirement for 2019 is provided at Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp.4-5. The details of the rate base and depreciation amounts by rate zone are provided in Table 6 below.

[15] EB-2017-0306/EB-2017-0307, Decision and Order, September 17, 2018, p. 33.

Table 6
ICM Threshold Rate Base and Depreciation Expense by Rate Zone

Line No.	Particulars ($ millions)	Rate Base	Depreciation	
		(a)	(b)	
	EGD			
1	2018 Board-Approved	6,246	305	/u
	Union			
2	2013 Board-Approved	3,734	196	
3	2019 Capital Pass-Through Amounts	1,597	43	
4	Total	5,331	239	

Eligible Capital Amount

Table 7 below compares the 2019 in-service capital forecast to the ICM materiality threshold by rate zone to calculate the maximum eligible incremental capital.

Table 7
Maximum Eligible Incremental Capital by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	2019 In-Service Capital Forecast	481.7	518.5[16]
2	Less: Materiality Threshold Value	468.5	375.2
3	Maximum Eligible Incremental Capital	13.1	143.3

[16] The 2019 In-Service Capital Forecast excludes $9.0 million related to the 2019 capital spend on Union's capital pass-through projects from its 2014-2018 IRM term. The 2019 spend on the capital pass-through projects is included in the AMP and Enbridge Gas Capital Expenditure Plan (shown in Table 2) but excluded from ICM eligibility. The 2019 capital spend on capital pass-through projects has another rate recovery mechanism.

The maximum eligible incremental capital for the EGD rate zone and Union rate zones is $13.1 million and $143.3 million, respectively. Enbridge Gas is seeking incremental ICM funding for specific discrete projects that fit within the maximum eligible incremental capital amount planned for each of the EGD and Union rate zones.

Table 8 below identifies the eligible capital projects and total capital in-service amounts for the ICM funding request of the EGD and Union rate zones. Only projects that are discrete and /u material have been included.

Table 8
2019 Incremental Capital Funding Request by Rate Zone

Line No.	Particulars ($ millions)	Total Project In-service Amount	Total Project ICM Funding Request	Difference
		(a)	(b)	(c) = (b-a)
	2019 In-service Capital Forecast			
	EGD Rate Zone			
1	Don River Replacement (1)	34.2	13.1	(21.1)
	Union South Rate Zone			
2	Kingsville Reinforcement	118.2	118.2	-
3	Stratford Reinforcement (1)	27.9	25.1	(2.8)
4	Total Union South Rate Zone	146.1	143.3	(2.8)
	2018 In-service Capital Forecast			
	Union North Rate Zone			
5	Sudbury Replacement[17]	91.9	91.9	-
6	Total Incremental Capital Funding Request	272.2	248.3	(23.9)

Notes:
(1) The total project in-service amounts of the Don River Replacement and Stratford Reinforcement project were reduced to recognize the total capital spend on the eligible projects exceeds the maximum eligible incremental capital from Table 7. In Union rate zone, there is no impact to customers of reflecting the reduction in only one project because the Kingsville and Stratford Reinforcement projects will be allocated to rate classes using a common allocator.

Enbridge Gas is requesting incremental capital funding during the current deferred rebasing period for the Sudbury Replacement project as part of this proceeding. Due to the October 2018

[17] The 2019 spend for the Sudbury Replacement Project will be managed under the ICM Threshold.

in-service date, the project falls between qualifying for incremental rate treatment under Union's 2014-2018 capital pass-through mechanism and qualifying for incremental rate treatment under the ICM. The project meets Union's 2014-2018 IRM capital pass-through criteria, including a full year revenue requirement[18] of approximately $9 million, but was not in-service for a full year during the 2014-2018 term of Union's last IRM. However, there was a significant need to replace the pipeline in order to continue to maintain safe and reliable service to the Sudbury market. Delaying the leave to construct application and construction in order to confirm the funding mechanism for the project was simply not an option. If the project was delayed, integrity concerns could have become more serious, with the risk of a potential failure increasing over time.

Given the magnitude of the $95.3 million investment in the Sudbury Replacement project, incremental funding of the project is required. The cumulative revenue requirement of the project from 2018 through 2023 is over $47 million. Union was not able to reprioritize 2018 Capital investment in order to fund this investment using existing rates. The purpose of the capital pass-through mechanism was to provide a means for Union to make significant investments under its price cap plan. Given that the timing of the investment in the Sudbury Replacement project occurred in late 2018, Enbridge Gas will be impacted by the first full year revenue requirement in 2019, during which time the Incremental Capital Module will apply. Enbridge Gas is seeking recovery of the prudently incurred Sudbury Replacement project costs beginning in 2019 under

[18] The annual revenue requirement criteria of Union's 2014-2018 IRM capital pass-through mechanism was 'a minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold")'.

the ICM mechanism because of the transition to ICM from the capital pass-through funding mechanism for the deferred rebasing period.

2.2 NEED

Means Test

A distributor must also pass the Means Test in order to be eligible for ICM funding. As defined by the Board, if a distributor's regulated return in its most recent calculation exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.[19]

EGD filed its 2017 Earnings Sharing and Deferral and Variance Account Clearances Application on June 27, 2018.[20] EGD's actual 2017 ROE was calculated to be 10.27% which was 149 bps above the 2017 Board-approved ROE of 8.78%. EGD's 2017 ROE calculations are provided at Appendix C.

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[19] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.15.

[20] EB-2018-0131, Exhibit B, Tab 1, Schedule 1.

Union filed its 2017 Disposition of Deferral Account Balances and 2017 Utility Earnings on June 6, 2018.[21] Union's actual 2017 ROE was calculated to be 9.16% which was 23 bps above the 2013 Board approved ROE of 8.93%. Union's 2017 ROE calculations are provided at Appendix D.

Discrete and Material Projects

ICM funding requests must be based on discrete, material projects. As defined in the Board ACM report, "amounts must be based on discrete projects, and should be directly related to the claimed driver. The amount must be clearly outside of the base upon which the rates were derived".[22] Also, as per the MAADs Decision, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.[23]

Each eligible capital project as identified for the EGD rate zone and Union rate zones are discrete projects that exceed the materiality level of $10 million. These projects have been evaluated as part of the capital planning process, described in the AMPs, which can be found at Exhibit C1, Tab 2, Schedule 1 and Tab 3, Schedule 1. Each project is distinct, with significant influence on Enbridge Gas's operations as described in Table 9.

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[21] EB-2018-0105, Exhibit A, Tab 2.
[22] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.
[23] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-33

2.3 PRUDENCE

The capital expenditures of the projects for which Enbridge Gas is seeking ICM funding approval for the EGD rate zone and Union rate zones are prudent and represent the most cost effective option for ratepayers.

The business case summaries in Table 9 below provide a description of each of the projects' need and prudence, with an overview of options considered.

Table 9
Business Case Summaries for ICM Projects by Rate Zone

EGD Rate Zone

NPS 30 Don River Replacement	
Budget: $35.4 million In-Service Date: December, 2019 In-Service Capital Spend: $34.2 million 2019 in-service; $1.1 million 2020 in-service	Category of Investment: System Renewal Project Description and Drivers: • Replacement of approximately 0.25 km of NPS 30 XHP on the Don River Bridge crossing with a new NPS 30 XHP under the Don River through the use of trenchless technology (microtunnel), and abandonment of the existing pipeline. Removal of the bridge and the abandoned pipeline to follow. • Studies have identified structural issues with the Bridge that can become further impaired during flood events which could cause the Bridge to fail resulting in catastrophic failure of the pipeline. • The pipeline is a critical feed to the densely populated urban Toronto area. Damage to this crossing at peak design temperature would result in the loss of ~ 92,500 customers, and may take days or weeks to restore service, once the pipeline issue has been addressed. Other Options Considered: • *Bridge Remediation:* This option would not require the NPS 30 pipeline to be replaced. Rather, the Bridge itself would be remediated to ensure structural stability against

	future flood events. Preliminary discussions identified the need for the use of some kind of sheet pile structures as a permanent remediation for the erosion around the bridge abutments. Based on the sensitivity of the adjacent 1911 (107 year old) twin bell and spigot 30" cast iron sanitary sewer mains (on wood piles), this option was deemed not viable. Due to the associated risk with working in the vicinity of these twin sanitary sewers, the option to remediate the bridge was not considered to be an acceptable alternative and therefore an estimated cost and timeline were not completed. • *Bridge Rebuild & Pipe Replacement:* Through the consultation process, TRCA provided Enbridge with options to consider for the replacement of the NPS 30 Don River Bridge crossing. One of these options included the possibility of using another above ground crossing. Enbridge explains how City of Toronto Bridges and Structures does not allow pipelines to be installed on bridges. The installation of structural supports to install the pipeline adjacent to existing bridges and create a new bridge to cross over the river would require very large supports. These supports would require footings in the river or on the river bank and there are already a number of structures in this area that would conflict with this approach. In addition, from an Enbridge construction and maintenance perspective, the installation of a pipeline on a bridge is deemed to be a last resort. As a result of all the above, this was not considered a viable alternative and therefore, an estimated cost and timeline was not completed. • *Direct Pipe Construction Method*: Under this alternative, the bridge would not be utilized and it would eventually be removed. The difference with this alternative relative to the proposed Project is the utilization of a different construction method for replacing the NPS 30 pipeline below ground under the river. During consultation the Direct Pipe method of construction and route considered for that methodology did not satisfy stakeholder concerns and conditions related to possible impacts to the TRCA's existing West Flood Protection Landform (FPL) and/or their proposed East FPL. As such a cost estimate, timelines and environmental impacts were not completed for this option as it was not a viable option. The Don River Replacement project was subject to a leave to construct application in EB-2018-0108. In its Decision and Order dated November 29, 2018, the OEB found that this project is needed to ensure the safe operation and reliability of the Don Valley Pipeline, as failure to address the risk associated with potential damage to the 89-year old bridge and existing pipeline could have a significant adverse impact on the gas supply to a large

	number of residential, commercial and industrial customers. The OEB also found that EGD adequately addressed environmental issues, land matters, design and safety requirements and adequately discharged the duty to consult with impacted Indigenous communities.[24] The budget is updated from the EB-2018-0108 filing budget of $25.6 million. It covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

Union Rate Zones

Sudbury Replacement Project	
Budget: $95.3 million In-Service Date: October, 2018 In-Service Capital Spend: $91.9 million 2018 in-service; $3.4 million 2019 in-service	<u>Category of Investment</u>: System Service <u>Project Description and Drivers</u>: • Build 20 km of NPS 12 pipeline in the Sudbury area to replace two sections of NPS 10 pipeline in the City of Greater Sudbury, predominately constructed in 1958 • Union's Integrity Management Program identified multiple integrity issues through inspections and investigative digs • Increasing the size of the pipeline to NPS 12 provides capacity for future growth on the Sudbury system <u>Options Considered</u>: • Union considered replacing the existing pipeline with another pipeline of the same size (NPS 10), or only replacing those segments of the pipeline identified as having integrity concerns • In addition to not serving the forecasted growth in the Sudbury area, replacing the NPS 10 pipeline with NPS 10 pipeline would not solve the pigging issues of having dual diameter pipelines • Replacing only those segments identified as having integrity concerns would result in inefficiencies related to the individual replacements and future integrity concerns that may require replacement • This alternative would also not meet future growth in the Sudbury area • Increasing the pipeline size from NPS 10 to NPS 12 is consistent with Union's practice to provide capacity for anticipated demand growth

[24] EB-2018-0108, Decision and Order, November 29, 2018, pp.1-9.

	• The incremental cost of the NPS 12 pipeline over the NPS 10 is forecast to be $1.5M (a 2% increase in the cost of project) resulting in an expected capacity increase of the Sudbury Lateral System of 5% • Installing NPS 12 pipeline is the lowest cost option to meet the capacity requirement in the Sudbury area The Sudbury Replacement project was subject to a leave to construct application in EB-2017-0180. In its Decision and Order dated September 28, 2017, the OEB found that the proposed pipeline was in the public interest. In reaching this decision, the OEB accepted Union's evidence that the project "is needed to maintain a safe and secure supply of gas in the Sudbury area"[25] and found the cost estimates "acceptable to address potential safety and security issues from the existing pipeline".[26] The OEB also found that Union adequately addressed environmental issues, land matters, design and safety requirements and adequately discharged the duty to consult with impacted Indigenous communities.[27] The budget is updated from the approved EB-2017-0180 filing budget of $74.1 million. It covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction.
Kingsville Reinforcement Project	
Budget: $121.4 million Projected In-Service Date: November, 2019 In-Service Capital Spend: $118.2 million 2019 in-service; $3.2 million 2020 in-service	Category of Investment: System Service Project Description and Drivers: • Approximately 19 kilometers of transmission pipeline in the Town of Lakeshore and the Town of Kingsville in the County of Essex • The Project is needed to respond to increasing natural gas demand in the Kingsville-Leamington market as well as increasing demand on the overall Panhandle Transmission System. • The Panhandle Transmission System is the primary pipeline to transport gas from Dawn to the Ojibway Valve Site in Windsor and feeds high pressure distribution pipelines servicing residential, commercial and industrial customers. • The Project reinforces the high-pressure Panhandle Transmission System to serve customers in the Kingsville-Leamington market area and to serve

[25] EB-2017-0180, Decision and Order, September 28, 2017, p.6.
[26] *Ibid*, p.7.
[27] *Ibid*, pp.8-11.

	future development in the market served by the Panhandle Transmission System. Options Considered: • Union considered alternatives including: different diameter pipeline, increased deliveries from Ojibway, looping the Panhandle system with NPS 36 pipeline, and distribution reinforcement with delayed construction of the NPS 12 pipeline to 2020 • A NPS 16 pipeline would be more costly in the longer term in relation to the upfront cost for the NPS 20 pipeline due to future facility requirements • Increased deliveries at Ojibway would be more costly over both the near and longer term with higher distribution reinforcement requirements, which could become underutilized in the long term • Looping the Panhandle system with NPS 36 requires the Kingsville lateral within the 20 year timeline and could result in underutilization of distribution reinforcement • Delaying the NPS 20 constructed in 2020 would result in the distribution facilities constructed in 2019 becoming underutilized • The Project is the preferred alternative to address the need in both the five-year and longer-term horizon. The Kingsville Transmission Reinforcement project was subject to a leave to construct application in EB-2018-0013. In its Decision and Order dated September 20, 2018 the OEB found that the proposed pipeline was in the public interest. In reaching this decision, the OEB found that Union "demonstrated the need for this Project - a transmission line with broad benefits to the Panhandle Transmission System"[28] and found that Union "appropriately followed the OEB's E.B.O. 134 test for transmission projects".[29] In finding that the project is the preferred alternative, the OEB noted the Project, "has the highest net present value, addresses incremental demand in the Kingsville-Leamington area in 2019 and is consistent with other, longer-term considerations for the Panhandle Transmission System."[30] The OEB also found that Union adequately addressed environmental issues and land matters, and adequately discharged the duty to consult with impacted Indigenous communities.[31]

[28] EB-2018-0013, Decision and Order, September 20, 2018, p.4.
[29] *Ibid*, p.5.
[30] *Ibid*, p.6.
[31] *Ibid*, pp.7-8.

	The budget is updated from the EB-2018-0013 filing budget of $105.7 million. It covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction.
Stratford Reinforcement Project	
Budget: $28.5 million Projected In-Service Date: November, 2019 In-Service Capital Spend: $27.9 million 2019 in-service; $0.6 million 2020 in-service	Category of Investment: System Service Project Description and Drivers: • Approximately 10.8 kms of NPS 12 pipeline and ancillary facilities in order to increase the capacity of Forest, Hensall and Goderich Transmission System serving the Northern portions of the Counties of Middlesex and Lambton and the Counties of Perth and Huron ("FHG Transmission System") • The Proposed Facilities are required to meet the increasing demands for natural gas starting in winter 2019 as the FHG Transmission System is forecasted to be fully utilized with no excess capacity available as of winter 2019 • In absence of the Project to increase capacity, Union will not be able to service additional customers • The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction Options Considered: • Union considered many alternatives including: a different diameter pipeline, a different length of pipeline and upgrading the maximum operating pressure ("MOP") of a portion of the FHG Transmission System • A NPS 10 pipe provides seven years of growth but significantly reduces the future capacity of the Stratford Line when compared to the NPS 12 option, it also does not adequately alleviate the constraint along the Stratford Line • The growth does not justify a NPS 16 reinforcement, and this size pipe would also require easement as it is too large to construct within the road allowance • There is insufficient growth to justify installing 15 km of NPS 12 pipeline, with potential for underutilization and different requirements for future reinforcement • Installing 7.6 km of pipeline does not provide the minimum of five years of growth and cannot accommodate any contract or large commercial

	growth, this alternative also has a significantly higher cost per-meter when compared to the proposed project • Upgrading the MOP of a portion of the FHG Transmission System does not provide the minimum of five years of growth and cannot accommodate any contract or large commercial growth until a Stratford Line reinforcement is completed • The Proposed Project is the most efficient project to provide the market with higher pressures and more robust gas supplies in order to meet the growing demand across the market region Union filed a leave to construct application with the OEB for the Stratford Reinforcement Project on November 2, 2018 under docket number EB-2018-0306.

3. CUSTOMER CONSULTATION

Enbridge Gas's customers believe investments should be made in maintaining existing reliability and in safety. Customers want a plan that will keep the system healthy and reliable in the long run, while also ensuring a demonstration of prudence in spending decisions. This feedback is considered in how Enbridge Gas plans, manages and develops assets within each of the rate zones. The projects for which Enbridge Gas is seeking ICM funding address integrity issues, provide for more robust supplies to the system and allow additional customer load to access the system.

4. CALCULATION OF REVENUE REQUIREMENT

Table 10 provides the incremental revenue requirement Enbridge Gas is seeking as ICM funding for 2019. The total 2019 impact of the ICM projects is $248.3 million with an associated incremental revenue requirement of $5.3 million in 2019. The incremental revenue requirement /u includes costs associated with the capital investment (return on rate base, depreciation expense and associated income taxes) as well as material incremental operating expenses (O&M and property taxes), if applicable.

Table 10
Total 2019 Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	Return on Rate Base	Operating Expenses	Income Taxes	2019 Total	
		(a)	(b)	(c)	(d)	
	EGD Rate Zone					
1	Don River Replacement	34	2	(406)	(370)	
	Union North Rate Zone					
2	Sudbury Replacement	6,504	2,973	285	9,762	
	Union South Rate Zone					
3	Kingsville Reinforcement	1,072	237	(4,666)	(3,358)	/u
4	Stratford Reinforcement	212	54	(1,032)	(766)	
5	Total Union South Rate Zone	1,283	291	(5,698)	(4,124)	/u
6	Total Incremental Revenue Requirement	7,822	3,265	(5,820)	5,267	/u

The return on rate base is calculated using the cost of capital parameters approved by the Board in EGD's 2018 Rate Adjustment Application (EB 2017-0086) for the EGD rate zone and in Union's 2013 Cost of Service application (EB 2011-0210) for the Union rate zones. Where applicable, rate base has been reduced by contributions in aid of construction received for the project.

Operating expenses include O&M, depreciation expense and property taxes associated with the project, if material. Because there is no material incremental O&M associated with the 2019 ICM eligible projects, O&M has not been included in the incremental revenue requirement calculation. Depreciation expense is calculated using Board-approved depreciation rates beginning the month following the in-service date of the project in accordance with the accounting policies of Enbridge Gas in 2019. Incremental property taxes associated with the project facilities has been included in the incremental revenue requirement.

Incremental income taxes as a result of the projects are calculated using the current tax rate. Income taxes include taxes on the equity and preference share return on rate base as well as the utility timing differences associated with the difference between utility income and taxable income. Income taxes are grossed up to account for the impact the additional revenue will have on income tax expense.

The revenue requirement for the 2019 ICM eligible projects has not been offset by incremental revenue as a result of customer growth associated with the projects. The projects are required to meet the increasing demands for natural gas in the area covered by the project. The revenue impact of the growth of the projects has been captured in the growth factor of the ICM Materiality Threshold value.

The total revenue requirement for each year of the deferred rebasing period is provided in Table 11.

Table 11
Total Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	2019 (a)	2020 (b)	2021 (c)	2022 (d)	2023 (e)	
	EGD Rate Zone						
1	Don River Replacement	(370)	1,137	1,227	1,218	1,207	
	Union North Rate Zone						
2	Sudbury Replacement	9,762	9,633	9,499	9,358	9,212	
	Union South Rate Zone						
3	Kingsville Reinforcement	(3,358)	10,269	10,598	10,681	10,731	/u
4	Stratford Reinforcement	(766)	2,146	2,221	2,249	2,267	
5	Total Union South Rate Zone	(4,124)	12,415	12,820	12,930	12,998	/u
6	Total Incremental Revenue Requirement	5,267	23,185	23,546	23,507	23,418	/u

The Don River Replacement, Kingsville and Stratford Reinforcement projects have a 2020 in-service capital forecast of approximately $1.1 million, $3.2 million and $0.6 million respectively that have been included in the calculation of the incremental revenue requirement for the deferred rebasing period. Enbridge Gas proposes to reduce the maximum eligible incremental capital in 2020 by the actual in-service amounts in that year related to the 2019 ICM approved projects. The detailed incremental revenue requirement detailed for each of the 2019 ICM projects for the deferred rebasing period is filed as Appendix E.

In the first calendar year of a project's in-service date, the revenue requirement may be a credit balance due to utility timing differences associated with the difference between utility income and taxable income. To reduce volatility in the impact to customers resulting from credit balances in the revenue requirement, Enbridge Gas proposes to net the credit balance in the in-service year with the balance in the second year and defer the ICM refund until the second year of the project. This proposal ensures the credit balance of the first year accrues to the benefit of customers, while maintaining stable predictable rate impacts during the deferred rebasing term. As shown in Table 11, column (a), the Don River Replacement, Kingsville and Stratford Reinforcement projects have credit balances in 2019 which will be netted with the balances in 2020 for recovery in the 2020 Rates application. Accordingly, Enbridge Gas is only seeking recovery of the Sudbury Replacement project revenue requirement in 2019.

5. COST ALLOCATION

Enbridge Gas is proposing to allocate the ICM Project revenue requirement to rate classes based on the most recently approved cost allocation methodology updated for the current year forecast.

For the Sudbury Replacement project in the Union North rate zone, Enbridge Gas proposes to allocate the associated revenue requirement to Union North rate classes based on a peak and average demand factor. This proposed cost allocation methodology is consistent with the allocation of Union North joint-use distribution mains costs approved by the Board in Union's 2013 approved cost allocation study (EB-2011-0210). The assets installed with the Sudbury Replacement project are categorized as joint-use distribution mains because they are used to provide service from the TransCanada interconnect location to the Sudbury-Espanola distribution system and do not exclusively serve a single identifiable customer. The allocation of joint-use distribution mains costs to Union North in-franchise rate classes is determined by taking a 50 percent weighting of a rate class' peak or maximum day demand requirements and a 50 percent weighting of a rate class' annual volume requirements.

As described in Section 4, Enbridge Gas proposes to recover the 2019 revenue requirement credit balance associated with the Don River Replacement project in the EGD rate zone, and Kingsville and Stratford Reinforcement projects in the Union South rate zone in 2020.

Enbridge Gas proposes to allocate the associated 2020 net revenue requirements with respect to the Don River Replacement project among different rate classes in EGD rate zone according to the most recent Board approved cost allocation methodology (EB-2017-0086) for the extra high pressure mains greater than 4 inch diameter. The allocator can be found at EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, Page 2, Item 2.1 (Delivery Demand TP > 4 inch allocator).

Enbridge Gas proposes to allocate the associated 2020 net revenue requirement with respect to the Kingsville and Stratford Replacement projects to Union South rate classes in proportion to the forecast Union South in-franchise design day demands. This proposed cost allocation methodology is consistent with the allocation of Other Transmission Demand costs approved by the Board in Union's 2013 approved cost allocation study. The assets installed with the Kingsville and Stratford Reinforcement projects will be categorized as Other Transmission assets. The allocation of Other Transmission costs recognizes other transmission lines are designed to meet Union South in-franchise demands on design day. The current Board-approved methodology for allocating Other Transmission costs was most recently approved by the Board in EB-2014-0182 (Union’s Burlington Oakville Pipeline Project).

Enbridge Gas proposes to update the 2020-2023 cost allocation factors for the 2019 ICM Projects as part of each of the respective annual rate proceedings to reflect the most current forecast allocation.

The 2019 cost allocation factors for each of the ICM projects and the allocation of project revenue requirement to the rate classes related to the Sudbury Replacement project is filed as Appendix F.

6. ICM UNIT RATES

Enbridge Gas is seeking approval of ICM unit rates for 2019 to recover the 2019 revenue requirement of the Sudbury Replacement project as part of this proceeding. To calculate the ICM unit rates for 2019, Enbridge Gas used the allocated 2019 revenue requirement and the forecast 2019 billing units for each respective rate class. Enbridge Gas proposes to embed the ICM unit rates in the delivery and transportation charges on the applicable rate schedule and customer bill. The derivation of the ICM unit rates to be included in 2019 rates is filed as Appendix G.

To reduce recovery variances over the deferred rebasing term, Enbridge Gas proposes to calculate the 2020-2023 ICM unit rates for the 2019 ICM Projects as part of each of the respective annual rate proceedings based on the annual revenue requirements provided in Table 11 and updated annual forecast billing units. Any variance from the revenue requirement amounts collected through the ICM rate riders and the actual revenue requirement incurred, will be tracked through the respective deferral account, as described in Exhibit B1, Tab 1, Schedule 1, Section 2.

7. ICM BILL IMPACTS

The bill impact associated with the ICM funding request for a typical Rate 01 residential customer consuming 2,200 m^3 annually in the Union North rate zone is an increase of $8.80 in 2019.

There is no bill impact in 2019 associated with the ICM funding request for a typical Rate 1 residential customer in the EGD rate zone as Enbridge Gas has proposed to include the credit balance of the 2019 revenue requirement for the Don River Replacement project with the 2020 revenue requirement.

There is no bill impact in 2019 associated with the ICM funding request for a typical Rate M1 residential customer in the Union South rate zone as Enbridge Gas has proposed to include the credit balances of the 2019 revenue requirement for the Kingsville and Stratford Reinforcement projects with the 2020 revenue requirement.

The ICM bill impacts by rate class are filed as Appendix H. The bill impacts do not reflect other proposed changes, effective January 1, 2019, as provided at Exhibit B1, Tab 1, Schedule 1, Section 8.

EGD RATE ZONE
Don River Replacement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2019	2020	2021	2022	2023
		(a)	(b)	(c)	(d)	(e)
	Incremental Rate Base Investment					
1	Capital Expenditures	13,124	1,114	-	-	-
2	Average Rate Base	547	13,288	13,737	13,390	13,044
	Incremental Revenue Requirement Calculation:					
	Return on Incremental Rate Base: (1)					
3	Long-term Debt Interest	16	386	399	389	379
4	Short-term Debt Interest	0	1	1	1	1
5	Preference Shares	0	6	6	6	6
6	Equity	18	431	445	434	423
7	Total Return on Incremental Rate Base	34	824	852	830	809
	Incremental Operating Expenses:					
8	Operating and Maintenance Expenses	-	-	-	-	-
9	Depreciation Expense (2)	-	327	347	347	347
10	Property Taxes (3)	2	7	7	7	7
11	Total Incremental Operating Expenses	2	334	354	354	354
	Incremental Income Taxes:					
12	Return on Equity and Preference Shares (line 5 + line 6)	18	436	451	440	428
	Utility Timing Differences					
13	Add: Depreciation Expense (line 9)	-	327	347	347	347
14	Less: Current Year Tax Deductions	(1,145)	(820)	(736)	(692)	(651)
15	Taxable Income (line 12 + line 13 + line 14)	(1,127)	(56)	62	94	124
16	Income Taxes Before Gross Up (line 15 x 26.5%) (4)	(299)	(15)	16	25	33
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (4) (5)	(406)	(20)	22	34	45
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	(370)	1,137	1,227	1,218	1,207

Notes:

(1) The return on rate base is calculated based on EGD's 2018 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.84%	4.70%	2.91%
Short-term Debt	0.56%	1.60%	0.01%
Preference Shares	1.60%	2.72%	0.04%
Equity	36.00%	9.00%	3.24%
Total	100.00%		6.20%

(2) Depreciation expense at EGD's 2018 Board-approved depreciation rates.
(3) Incremental property tax costs as a result of the project facilities.
(4) EGD's current provincial and federal tax rate is equal to 26.5%.
(5) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

UNION NORTH RATE ZONE
Sudbury Replacement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2018 (a)	2019 (b)	2020 (c)	2021 (d)	2022 (e)	2023 (f)
	Incremental Rate Base Investment						
1	Capital Expenditures	91,889	-	-	-	-	-
2	Average Rate Base	17,477	89,089	86,290	83,491	80,692	77,893
	Incremental Revenue Requirement Calculation:						
	Return on Incremental Rate Base: (1)						
3	Long-term Debt Interest	700	3,566	3,454	3,342	3,230	3,118
4	Short-term Debt Interest	(0)	(0)	(0)	(0)	(0)	(0)
5	Preference Shares	15	74	72	70	67	65
6	Equity	562	2,864	2,774	2,684	2,594	2,504
7	Total Return on Incremental Rate Base	1,276	6,504	6,300	6,095	5,891	5,687
	Incremental Operating Expenses:						
8	Operating and Maintenance Expenses	-	-	-	-	-	-
9	Depreciation Expense (2)	1,400	2,799	2,799	2,799	2,799	2,799
10	Property Taxes (3)	43	174	176	179	182	184
11	Total Incremental Operating Expenses	1,443	2,973	2,975	2,978	2,981	2,983
	Incremental Income Taxes:						
12	Return on Equity and Preference Shares (line 5 + line 6)	576	2,939	2,846	2,754	2,662	2,569
	Utility Timing Differences						
13	Add: Depreciation Expense (line 9)	1,400	2,799	2,799	2,799	2,799	2,799
14	Less: Current Year Tax Deductions	(9,238)	(4,948)	(4,651)	(4,373)	(4,111)	(3,865)
15	Taxable Income (line 12 + line 13 + line 14)	(7,262)	790	994	1,180	1,350	1,504
16	Income Taxes Before Gross Up (line 15 x 26.5%) (4)	(1,924)	209	263	313	358	398
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (4)	(2,618) (5)	285	358	425	487	542
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	101	9,762	9,633	9,499	9,358	9,212

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(2) Depreciation expense at Union's 2013 Board-approved depreciation rates.
(3) Incremental property tax costs as a result of the project facilities.
(4) Union's current provincial and federal tax rate is equal to 26.5%.
(5) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Kingsville Transmission Reinforcement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2019	2020	2021	2022	2023
		(a)	(b)	(c)	(d)	(e)
	Incremental Rate Base Investment					
1	Capital Expenditures	118,183	3,171	-	-	-
2	Average Rate Base	14,677	118,411	117,650	115,287	112,924
	Incremental Revenue Requirement Calculation:					
	Return on Incremental Rate Base: (1)					
3	Long-term Debt Interest	588	4,740	4,709	4,615	4,520
4	Short-term Debt Interest	(0)	(1)	(1)	(1)	(1)
5	Preference Shares	12	99	98	96	94
6	Equity	472	3,807	3,782	3,706	3,630
7	Total Return on Incremental Rate Base	1,072	8,645	8,589	8,417	8,244
	Incremental Operating Expenses:					
8	Operating and Maintenance Expenses	-	-	-	-	-
9	Depreciation Expense (2)	192	2,331	2,363	2,363	2,363
10	Property Taxes (3)	45	270	274	278	282
11	Total Incremental Operating Expenses	237	2,601	2,637	2,641	2,645
	Incremental Income Taxes:					
12	Return on Equity and Preference Shares (line 5 + line 6)	484	3,906	3,881	3,803	3,725
	Utility Timing Differences					
13	Add: Depreciation Expense (line 9)	192	2,331	2,363	2,363	2,363
14	Less: Current Year Tax Deductions	(13,617)	(8,948)	(7,985)	(7,209)	(6,527)
15	Taxable Income (line 12 + line 13 + line 14)	(12,941)	(2,711)	(1,741)	(1,044)	(439)
16	Income Taxes Before Gross Up (line 15 x 26.5%) (4)	(3,429)	(719)	(461)	(277)	(116)
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (4) (5)	(4,666)	(978)	(628)	(376)	(158)
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	(3,358)	10,269	10,598	10,681	10,731

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(2) Depreciation expense at Union's 2013 Board-approved depreciation rates.

(3) Incremental property tax costs as a result of the project facilities.

(4) Union's current provincial and federal tax rate is equal to 26.5%.

(5) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

UNION SOUTH RATE ZONE
Stratford Reinforcement - ICM Project Revenue Requirement

Line No.	Particulars ($000's)	2019 (a)	2020 (b)	2021 (c)	2022 (d)	2023 (e)
	Incremental Rate Base Investment					
1	Capital Expenditures	25,100	607	-	-	-
2	Average Rate Base	2,903	25,131	24,885	24,361	23,837
	Incremental Revenue Requirement Calculation:					
	Return on Incremental Rate Base: (1)					
3	Long-term Debt Interest	116	1,006	996	975	954
4	Short-term Debt Interest	(0)	(0)	(0)	(0)	(0)
5	Preference Shares	2	21	21	20	20
6	Equity	93	808	800	783	766
7	Total Return on Incremental Rate Base	212	1,835	1,817	1,779	1,740
	Incremental Operating Expenses:					
8	Operating and Maintenance Expenses	-	-	-	-	-
9	Depreciation Expense (2)	43	518	524	524	524
10	Property Taxes (3)	12	69	70	71	72
11	Total Incremental Operating Expenses	54	587	594	595	596
	Incremental Income Taxes:					
12	Return on Equity and Preference Shares (line 5 + line 6)	96	829	821	804	786
	Utility Timing Differences					
13	Add: Depreciation Expense (line 9)	43	518	524	524	524
14	Less: Current Year Tax Deductions	(3,002)	(2,112)	(1,870)	(1,674)	(1,502)
15	Taxable Income (line 12 + line 13 + line 14)	(2,864)	(765)	(526)	(346)	(192)
16	Income Taxes Before Gross Up (line 15 x 26.5%) (4)	(759)	(203)	(139)	(92)	(51)
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (4) (5)	(1,032)	(276)	(190)	(125)	(69)
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	(766)	2,146	2,221	2,249	2,267

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.30%	6.53%	4.00%
Short-term Debt	-0.03%	1.31%	0.00%
Preference Shares	2.74%	3.05%	0.08%
Equity	36.00%	8.93%	3.21%
Total	100.00%		7.30%

(2) Depreciation expense at Union's 2013 Board-approved depreciation rates.

(3) Incremental property tax costs as a result of the project facilities.

(4) Union's current provincial and federal tax rate is equal to 26.5%.

(5) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

ENBRIDGE GAS INC.

UTILITY SYSTEM PLAN

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 PURPOSE

This is Enbridge Gas's consolidated Utility System Plan ("Enbridge Gas USP") covering the 2019 to 2023 period. It describes how the company plans to drive operational effectiveness through strong asset management and meet the expectations set out in the Board's Renewed Regulatory Framework ("RRF").

The Applicants committed to file a consolidated USP at the hearing of the MAADs proceeding.[1] In the MAADs Decision, the Board found it "reasonable that a consolidated USP will not be available for 2019 and 2020 rates, but expects the applicants to file separate USPs as planned."[2] In line with the commitment at the hearing, the Company has worked diligently to provide a consolidated Enbridge Gas USP for this 2019 rate application with supporting Asset Management Plans ("AMPs"). However, consistent with the Board's MAADs Decision, Enbridge Gas will file an updated consolidated Enbridge Gas USP in its 2021 rate application along with any Incremental Capital Module ("ICM") funding request. In addition, any update to the Enbridge Gas USP will include further customer engagement to inform Enbridge Gas's plans.

[1] EB-2017-0306/EB-2017-0307 Hearing Transcript Volume One, May 3, 2018, p. 95.
[2] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, pp. 33-34.

As Enbridge Gas works through the integration of the two utilities, components of the Enbridge Gas USP and the AMPs are, and will continue to be separate. As discussed above, Enbridge Gas expects to be able to file an update to the Enbridge Gas USP and AMPs which reflects a further integrated utility with any ICM funding requests for 2021 rates and beyond. Fundamentally however, strong asset management that balances cost, risk and performance, while delivering value to customers has been at the core of EGD and Union's business for years and is demonstrated throughout the Enbridge Gas USP and AMPs.

Enbridge Gas's USP meets the needs of the utility's customers of the EGD and Union rate zones through strong asset management that supports the delivery of safe, reliable service.

1.2 OEB FILING REQUIREMENTS

On February 16, 2017, the OEB issued amended filing requirements for natural gas rate applications, the OEB Filing Requirements for Natural Gas Rate Applications (the "Gas Filing Requirements"). Section 2.2.6 of the Gas Filing Requirements provides the requirements for a USP. As discussed above, in the MAADs proceeding EGD and Union committed to filing a USP in support of Enbridge Gas's 2019 rate application. Enbridge Gas's USP fulfills the requirements in Section 2.2.6. In addition to the Gas Filing Requirements, there are several other Board policies which were referred to in the creation of Enbridge Gas's USP. These include elements from:

- The October 13, 2016 *Handbook for Utility Rate Applications* (the "Rate Handbook");

- the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report"), which under the framework is applied to all rate regulated utilities and is now referred to as the RRF;
- the OEB's guidelines for natural gas utilities' transportation and distribution system projects (E.B.O. 134 and E.B.O. 188)[3]; and
- Chapter 5 of the *Filing Requirements for Electricity Distributor Applications*[4], which provides further guidance from the Board on components of a Distribution System Plan, which can be informative to certain components of the USP.

A key component of Enbridge Gas's USP is demonstrating to the Board and stakeholders how the objectives of the RRF have been met through a principled asset management approach. Specifically, how the USP drives an outcome-based approach to asset management.

1.3 ENBRIDGE GAS'S SYSTEM OVERVIEW

Enbridge Gas's values of integrity, safety and respect, along with its strategic priorities, guide decision making in the EGD and Union rate zones. Asset management provides the necessary structure to make informed asset decisions and execute the resulting actions, as aligned with the RRF framework.

[3] Gas Filing Requirements, February 16, 2017, p. 21.
[4] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 5 Consolidated Distribution System Plan, July 12, 2018.

Enbridge Gas's strategic priorities and alignment with the RRF are shown in Table 1.

Table 1
Enbridge Gas Strategic Priorities

Strategic Priority	RRF Outcome	Description
1. Safety and Operational Reliability	Customer Focus and Operational Effectiveness	Ensuring the safety of communities, and preventing harm to the public, employees, and the environment is Enbridge Gas's highest duty. Every injury and incident can be prevented, and every employee has a responsibility to act in accordance with that duty. Safety information for Enbridge Gas customers, contractors and the communities in which we operate can be found on EGD's and Union's safety pages.
2. Execute Capital Program	Operational Effectiveness	Project execution is integral to both near-term financial performance, and to positioning Enbridge Gas for long-term success. It therefore remains a critical priority for execution teams to manage challenges and engage proactively with communities and customers. Forecasting a long term asset investment plan and ensuring money is spent on the right things at the right time helps to plan ahead for execution. Aligning roles and organization structure to support Asset Management enables the entire company to remain integrated with the execution of Asset Management and the resultant capital plan.
3. Maximize Value of Core Business	Customer Focus and Operational Effectiveness	Enbridge Gas expects customer growth to remain strong, driven by Ontario population growth and demand for natural gas as a cost effective source of energy. Enbridge Gas also receives expansion requests to help

		bring natural gas to remote locations, including Indigenous communities. A strong Asset Management program allows for value-based decision making, where optimizing/prioritizing is based on risk and opportunity.
4. Position for Long-term Growth	Public Policy Responsiveness and Financial Performance	Enbridge Gas is committed to being part of the transition to a lower carbon economy. Examples of this include support for programs such as Renewable Natural Gas, Compressed Natural Gas, and the integration of gas and electric infrastructures using technology like combined heat and power, geothermal loops and hydrogen storage and blending.
5. Strengthen Financial Position	Financial Performance	Enbridge Gas is committed to ensuring the proper governance structure and level of management oversight to enable the Company to invest capital in the most efficient and effective way to meet the Company’s obligations, ensure safety, and maximize the value of the investments. It also enables the business to plan and execute work in a timely fashion with minimal administrative burden, responding quickly to the demands of the customers that the Company serves.
6. Complete Integration and Transformation	Customer Focus, Operational Effectiveness and Financial Performance	The integration of Enbridge Gas will drive efficiencies and synergies, create new opportunities for growth, and form a stronger platform to deliver superior value and service to customers. Over time the AMP process will integrate the EGD and Union plans into one.

EGD Rate Zone

EGD has approximately $9.4 billion of assets, employs about 2,100 people and distributes natural gas to over 2.1 million customers (including residential, commercial, industrial and transportation customers across Ontario). EGD's franchise service area includes Toronto, Ottawa, Peel, Dufferin, York, Durham, the Niagara Peninsula, Brockville, Peterborough, Barrie, Collingwood and other Ontario communities (about 100 communities). EGD owns and operates 37,600 kilometres ("km") of pipelines (mains) for the transportation and distribution of gas, plus service pipes to transfer gas to meters on customer premises. In addition, EGD owns approximately 3 billion m^3 (107 Bcf) underground gas storage facilities (91 Bcf regulated & about 64 Bcf unregulated). EGD also operates about 114 Bcf (including 7 Bcf allocated to Union) and rents additional storage for a total of 134 Bcf. EGD distributes approximately 464 Bcf, or about 13 billion m^3 of natural gas per year (daily distribution varies seasonally). EGD's supporting assets include service facilities, fleet, and information technology assets. The fleet assets include 654 light duty vehicles, 210 medium duty vehicles and 338 heavy equipment units. EGD's facilities include 12 operations depots, three regional operations and administrative centres, and one head office. The information technology assets include over 120 key applications and technologies plus associated hardware that provide critical functionality to effectively run the business.

Union Rate Zones

Union has approximately $8.9 billion of assets and employs about 2,300 people. Union's natural gas assets include over 70,000 km of distribution, transmission, and storage pipelines, over 2,800 system stations, about 1.5 million customer stations including meters, approximately 4.8 billion m^3 (170.5 Bcf) or 188.1 PJ of natural gas storage capacity, 760,000 horsepower of compression, and one liquefied natural gas facility. Union's supporting assets include service facilities, fleet vehicles, and information technology assets. The administration facilities include 83 administration buildings located across Ontario to support Union's functional business needs and activities. The information technologies assets include 80 applications and technologies plus associated hardware that provide critical functionality to effectively run the business.

2.0 Economic and Planning Assumptions

2.1 Current Budget Cycle Assumptions

The Company completes an annual budget and multi-year long range planning ("LRP") process, which reflects a forecast of customer demands, revenues, operating costs and capital investments. This process is underpinned by a number of key economic and planning assumptions. These assumptions are obtained from both internal and external sources and approved by management.

The key assumptions and source of information are detailed below:

1. Revenue inflation: The revenue escalator is established as part of the rate mechanism under which the Company operates. Beginning in 2019, the Company will be operating under a price cap mechanism, using the macroeconomic measure Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") less a stretch factor of 0.3% in accordance with the MAADs Decision;
2. Labor escalation: This assumption is determined by the corporate compensation function and is applied to non-unionized salary and wage costs;
3. Non-wage inflation: This assumption is determine by the corporate planning and forecast function and is applied to non-wage operating and maintenance costs;
4. Foreign exchange and interest rates: These financial indicators are issued from the corporate treasury function. These assumptions are based on the average of forecasts from external sources and historical differentials;
5. Customer Attachments: The forecast for customer attachments includes new housing starts, residential conversions, commercial customer additions and small industrial additions. This forecast is based on historical customer counts as well as external housing forecasts combined with market share and natural gas penetration rates. Known projects are also included;
6. Average Use ("AU")/Normalized average consumption ("NAC"): The AU/NAC forecast for residential customers is based on multiple regression analysis and includes several variables including weather normal, energy efficiency, price signals and foreign exchange

rate. The forecasted AU/NAC is determined by the Company's internal demand forecasting function as per OEB approved methodologies.

The key assumptions are approved by management and distributed to the relevant forecasting and planning function to incorporate into the relevant budget and LRP process, as detailed in Section 3.1.

2.2 EXPECTATIONS OF NATURAL GAS PRICES

Growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (price differential between location), and North American wide infrastructure projects.

The major contributing factor to Union's recent infrastructure expansion relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and shippers that are accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

Although difficult to forecast, going forward Union expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Ontario Local

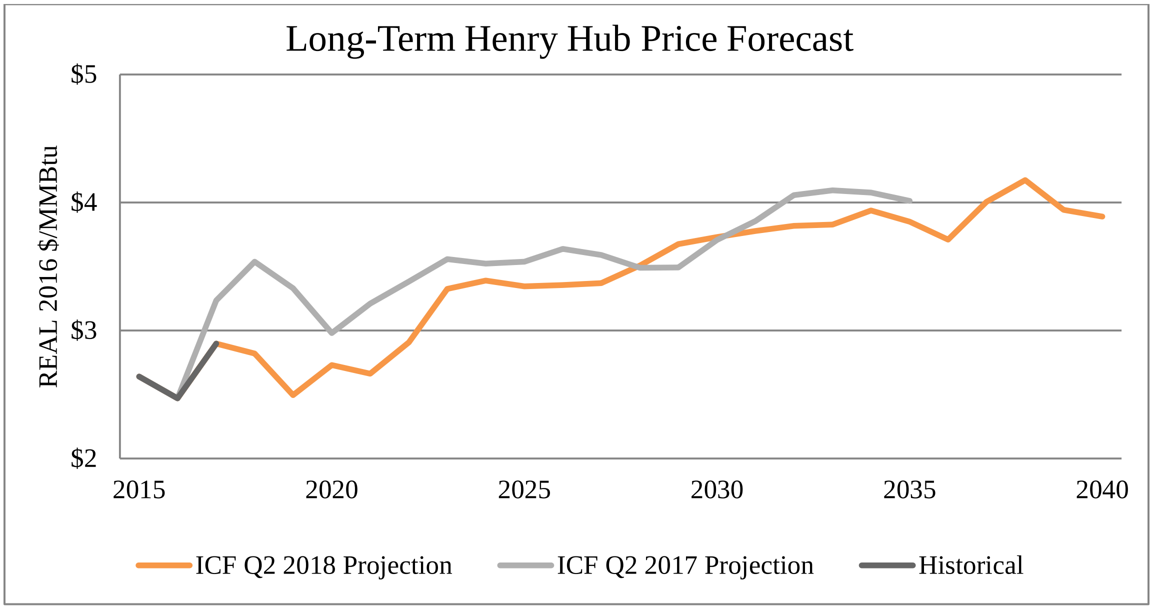
Distribution Companies ("LDCs"), as well as natural gas fired generation due to Ontario's nuclear refurbishment plan, when executed.

Natural Gas Price Signals

The emergence of shale production has increased dramatically since 2007 and the increase in available supply has put downward pressure on natural gas prices across North America. As indicated above, continued development of the Marcellus and Utica plays in the U.S. Northeast is the main driver of supply growth in total U.S. shale gas production. A rebound in drilling activity will lead to continued production growth and increases in per-well production. These two factors have reduced costs and made gas supplies more responsive to price changes, which should limit upward pressure on prices.

Natural gas prices set at Henry Hub are generally seen to be the primary price set for the North American natural gas market with locational basis differentials based off NYMEX Henry Hub. ICF indicates that Henry Hub prices will remain in the $3-4 USD/MMBtu range in the longer term as shown in Figure 1. The 2018 projection from ICF is slightly lower than the ICF projection from 2017.

Figure 1



"Source: ICF Forecast: Natural Gas – Strategic, Q2 2018 Outlook. Used with permission"

3.0 Investment Planning Process

3.1 Company Budget and Long Range Planning Process

3.1.1 Overview

Each year Enbridge Gas completes an annual budget and multi-year LRP process. Prior to 2019 the process was completed separately for EGD and Union. Starting in 2019 the process will be completed for Enbridge Gas as a whole. This process reflects Enbridge Gas's forecast of customer demands, revenues, operating costs, and capital investments. The budget and LRP balance the need to maintain safe and reliable operations that meet the demands of current and new ratepayers, while ensuring Enbridge Gas's financial viability, including an appropriate level of shareholder return.

The demand forecast is the starting point for the budget and LRP process and includes a detailed customer and volume forecast. The demand forecast provides inputs into the four main components of the Company's financial budget and LRP process listed below, as well as the Gas Supply Plan process detailed with the Distribution Revenue process.

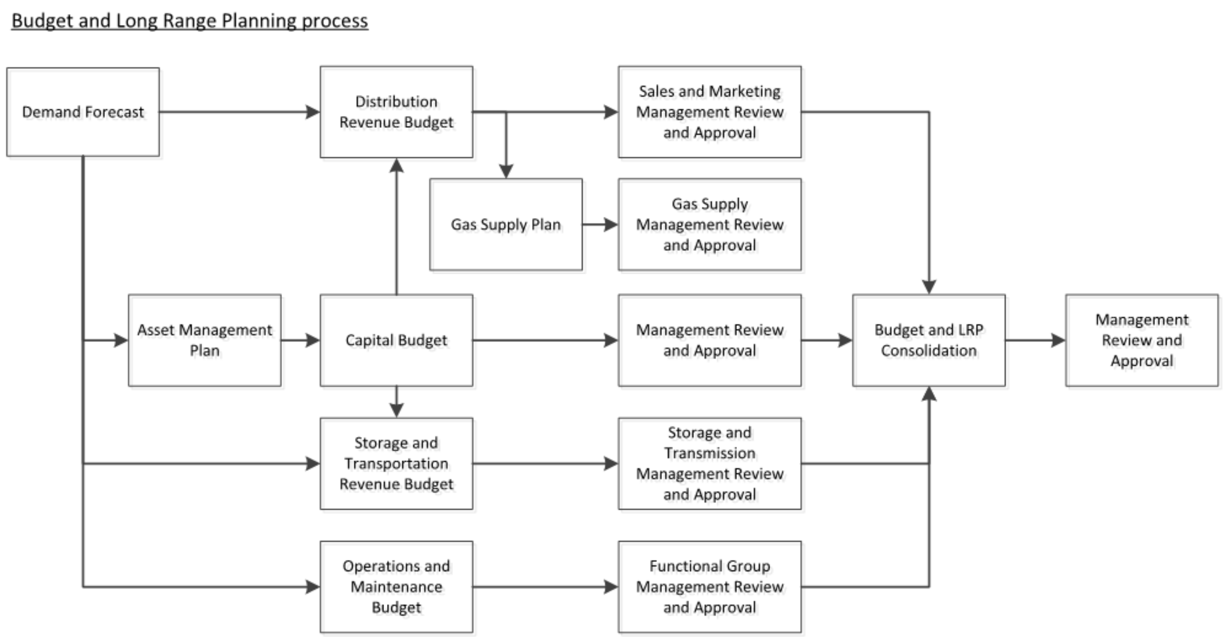
Each component of the budget and LRP is individually described in the following sections:

1. Distribution Revenue
2. Storage and Transportation Revenue
3. Operations and Maintenance Costs
4. Capital Investment

Figure 2 provides a process map for the budget and LRP process. The budget and LRP components include the impact of economic variables such as interest rates, foreign exchange rates, inflation levels, Gross Domestic Product ("GDP") forecasts, and provincial housing starts, where applicable.

Figure 2

Budget and Long Range Planning Process Map



3.1.2 Demand Forecast

The starting point for the planning process is the customer, demand and volume forecast. This forecast underpins the development of both the revenue and cost components of the budget and LRP, and is used as an input into the AMP process.

3.1.2.1 Distribution Revenue Budget

The distribution revenue budget is comprised of two distinct segments of customers: general service and contract. The forecast for each segment applies forecast rates for each year of the budget and LRP to the demand forecast in order to derive the revenue forecast for the utility.

Distribution Revenue - General Service Customers

The general service customer segment consists of residential and low-volume apartment, commercial and industrial customers. This segment is heat sensitive and also influenced by: economic conditions, housing starts, price, efficiency factors and energy conservation measures. Econometric models are used to develop this forecast. Together these customers consume more natural gas from November through March than the spring and summer months.

The demand forecast for the general service segment is based on the current customer base plus forecasted additions less customer attritions. Gas usage is estimated for those current and forecasted customers and applied to the forecasted rates to create a revenue forecast.

Distribution Revenue - Contract Class Customers

The contract customer segment typically has higher consumption levels and is less heat-sensitive than the general service customer segment. Consumption for these customers is based primarily on process load, which is linked more closely to factors such as general economic health, industry growth, and customer expansion/contraction plans. Energy conservation measures and various macro-economic factors also play a role in consumption levels of this customer segment.

The demand forecast for this segment is based on the current contract parameters plus or minus changes in requirements for those customers, as well as the requirements of potential new customers. The forecast is based on a variety of methods including: direct engagement with current and potential customers, a thorough assessment of growth and demands by geographic area or market sectors (e.g. the power or chemical market), and by general trends reflective of industry and general economic conditions. Where available, direct customer input is factored in the Company forecast.

Distribution Revenue Budget Review and Approval

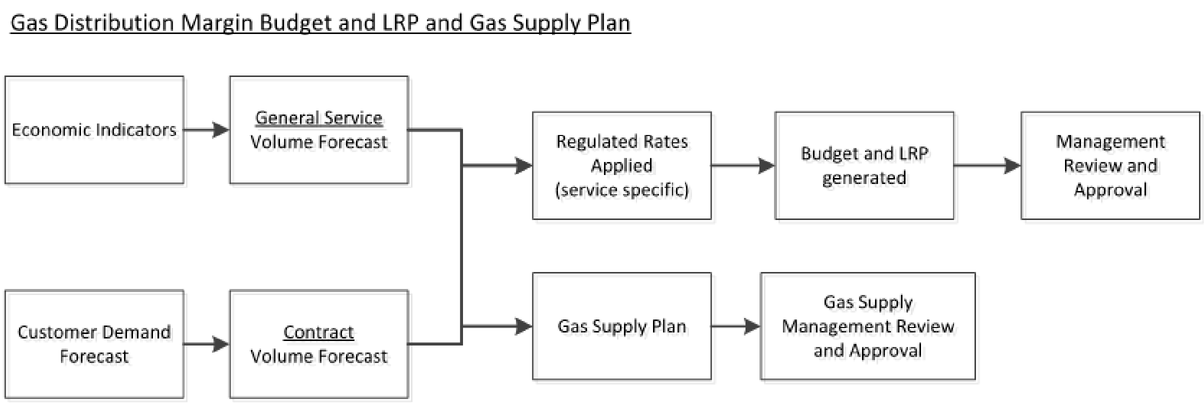
The revenue forecasts for both the general service and contract class customers are consolidated and presented to the management team accountable for distribution revenue for review and approval. It is subsequently consolidated by Finance with the broader Company budget, and is reviewed and approved by the Company's senior management team.

Distribution Demand Forecast as an Input to the Gas Supply Plan

The demand forecast for the Distribution segment is also an input for the Gas Supply Plan process. Econometric and regression analysis is combined with historical consumption data and customer specific consultation to provide the basis for the customer forecast. This forecast is then combined with forecasted customer usage to derive the total throughput volume forecast. The volume forecast is provided to the gas supply function for inclusion in the development of the Gas Supply Plan.

The objective of the Gas Supply Plan is to identify the most efficient combination of upstream transportation, supply purchases, and storage assets required to serve sales service and bundled direct purchase customers' annual, seasonal and design day natural gas delivery requirements under a set of gas supply planning principles. Balanced consideration of these principles ensures that customers have access to secure, reliable and diverse natural gas purchased at a prudently incurred cost.

Figure 3
Distribution Revenue Budget and Gas Supply Plan



3.1.2.2 Storage and Transportation Revenue Budget

The Storage and Transportation ("S&T") budget and LRP revenues are attributed to the sale of services using the Company's regulated storage and transportation assets.

Storage Revenue

The demand forecast, through the Gas Supply Planning process, is used to determine the amount of storage service required by in-franchise customers. These are customers who reside in the Company's franchise area and require storage services to support their associated gas consumption needs. The Company's utility storage revenue is based on the sale of excess utility space, on a short term basis, to the Company's unregulated portion of the business for re-marketing to the competitive storage market. Available storage capacity is the excess of utility space that is not required for the regulated in-franchise markets. The unregulated business sells the storage to third parties, and the regulated utility receives a share of the net revenues. This is in accordance with the decision rendered by the Board as part of the Natural Gas Electricity Interface Review ("NGEIR").

Transportation Revenue

The transportation revenue budget is based on the Company's sale of its transmission pipeline capacity. The Company sells both short-term and long-term transportation capacity, as well as exchanges.

The demand forecast, through the Gas Supply Planning process, is used to determine the amount of transportation service required to meet the needs of in-franchise customers. Additional capacity is available for sale to ex-franchise customers. Ex-franchise customers are not directly associated with consumption within the Company's franchise area, but use the Company's services to transport gas to and from other interconnecting pipelines and markets or to supplement services offered to in-franchise customers. The transportation revenue forecast is based on current contracted demands as well as forecasted future demands. Existing contract parameters are reviewed to understand current contracted demands. Ongoing customer discussions inform the Company of changes to future demands and requirements of potential new transmission customers. This information is obtained through ongoing customer engagement with existing and potential customers, and through the transportation capacity open season process.

Capacity available for sale for transportation services is the transportation capacity in excess of what is used for purposes of serving the Company's in-franchise customers. If available capacity is not sufficient to meet the existing and forecasted future demand for transportation services, additional capacity may be created through the construction of new facilities to meet the incremental demand. Capacity demands for both in-franchise customers and ex-franchise customers are factored into the AMPs for asset classes providing these services.

Transportation services for rate classes M12/M12-X, M16, and C1 long-term services are priced based on regulated rate schedules. C1 short-term transportation services and exchanges are based on negotiated rates. The transportation revenue forecast is the product of the forecasted rates for the respective transportation services, applied to the forecasted demands.

S&T Revenue Budget Review and Approval

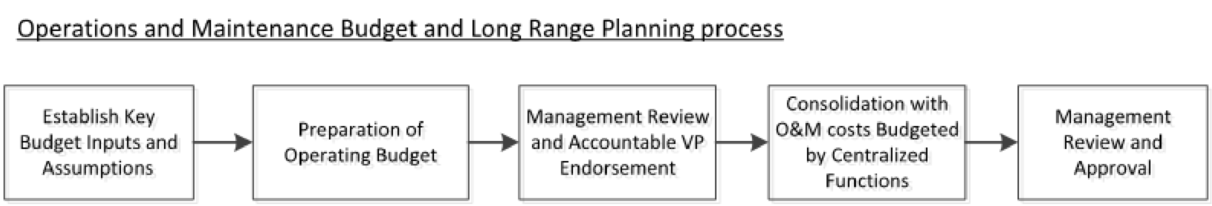
The revenue budget and forecast for utility storage and transportation services are consolidated and presented to the Management team accountable for utility S&T revenue for review and approval. It is subsequently consolidated by Finance within the broader Company budget, and is reviewed and approved by the Company's senior executive management team.

3.1.3 Operating and Maintenance ("O&M") Expense Budget Process

The major steps in the O&M Budget process are illustrated in Figure 4 and described below:

1. Establish Key Budget Inputs & Assumptions;
2. Preparation of Operating Budget;
3. Management Review and Accountable VP Endorsement;
4. Consolidation with O&M costs Budgeted by Centralized Functions;
5. Management Review and Approval.

Figure 4
O&M Budget Process



Establish Key Budget Inputs and Assumptions

Assumptions are obtained by Finance from corporate and external sources for key input variables, including GDP growth, inflation, foreign exchange rate and expectations for compensation increases. These inputs and assumptions are reviewed by senior management and then used in the development of the Operating & Maintenance budget.

Preparation of Operating Budget

An operating budget is developed for each accountable area under a Vice President’s reporting structure. The starting point for the operating budget is the previous year’s budget/LRP which is then adjusted for compensation changes and inflation. The budget is then adjusted for any new program additions or deletions, or any program with material changes. Ongoing O&M costs associated with capital projects that have been placed into service are also incorporated. Changes in staffing requirements are considered, as is the need to employ consultants or contract employees in order to complete the required workload in a safe, timely and cost effective manner. Based on the resources required to carry out the work plan, relevant material, equipment and vehicle costs are incorporated into the detail. In addition, productivity and efficiency initiatives are identified to help manage cost increases.

Management Review and Accountable Vice President Endorsement

The budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. A final budget for each area is endorsed by the accountable Vice President responsible for each area.

Consolidation with O&M costs Budgeted by Shared Service Functions

There are a number of Shared Service functions such as Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability that are resident at the Company and provide specific utility based shared services. These functions are budgeted centrally at the corporate level, with input from the business units, including the utilities segment, on the business support required. These functions use a corporate cost allocation process to ensure that the Company is paying an appropriate amount for the services it receives from these centralized functions. The endorsed O&M budget for each Company Vice President is then consolidated with the O&M budgets for the shared service functions to arrive at the total utility O&M budget. O&M costs supporting unregulated activities are not included in the regulated utility O&M budget, but are included in the overall Company budget.

Management Review and Approval

The consolidated O&M budget is then consolidated by Finance with the broader Company budget and is reviewed and approved by the Company's Senior Executive management team.

3.1.4 Capital Budget Process

The Company's capital budget process ensures that capital is allocated in a way that maximizes the value of life cycle-based capital while mitigating risk to the lowest practical level. This requires a combined effort from the Asset Management team, the business, and Finance to govern, prioritize, and execute the capital projects.

There are two primary objectives of the capital budget process:

1. Ensure the proper governance structure and level of management oversight to enable the company to invest capital in the most efficient and effective way to meet the Company's obligations, ensure safety, and maximize the value of the investments; and
2. Enable the business to plan and execute work in a timely fashion with minimal administrative burden, responding quickly to the demands of the customers that the Company serves.

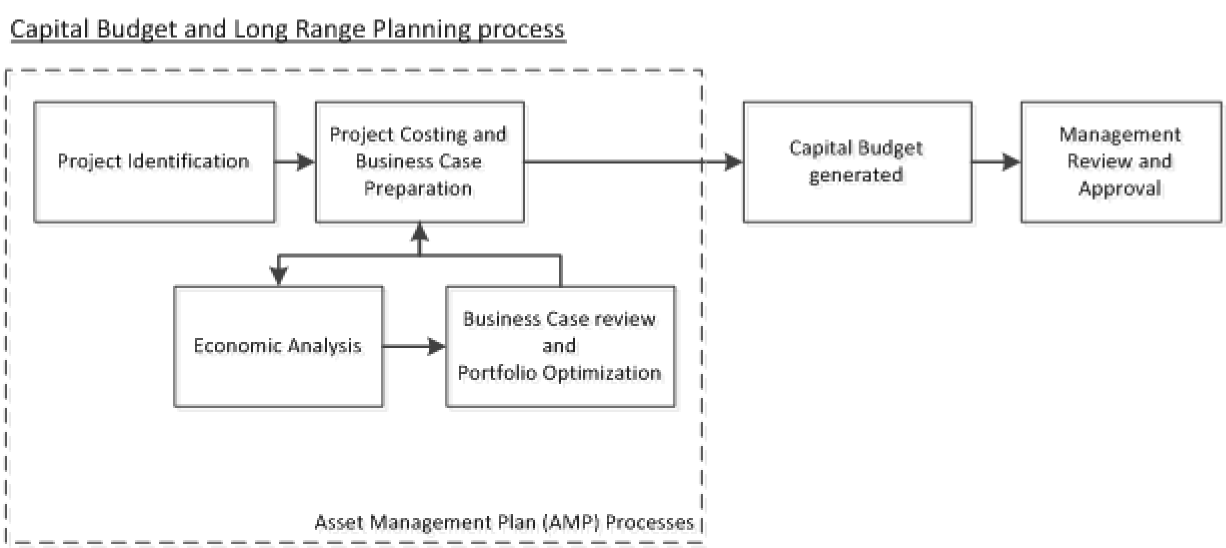
The capital budgeting process is underpinned by the AMP. The AMP and how it is developed is detailed in Section 5. The AMP uses risk assessment methodologies to assess capital projects.

These risk assessment methodologies, in combination with the defined risk tolerances, form the basis for the selection and prioritization/optimization process for capital investments.

The major steps in the capital budgeting process are illustrated in Figure 5 and include:

1. Project Identification;
2. Project Costing and Preparation of Business Cases;
3. Economic Analysis;
4. Business Case Review and Portfolio Prioritization/Optimization;
5. Consolidation, Management Review and Approval.

Figure 5
Capital Budget and LRP Process



Project Identification

The need for a project is identified through the AMP process. The main drivers for capital expenditures are:

i. System integrity expenditures required to maintain or enhance the integrity of the company's plant, as well as to ensure compliance with codes and regulations governing the industry;
ii. System replacement expenditures required as a result of requests from municipalities and others under the terms of franchise or other occupancy agreements;
iii. Capital expenditures to replace plant, vehicles and equipment, computer hardware and software as a result of age, condition, or obsolescence;
iv. Capital expenditure requirements to meet expected growth as identified through the demand/revenue planning process and the gas supply planning process;
v. New programs that result in the need for capital expenditures.

Specific capital projects are identified to address the needs articulated above.

Project Costing and Preparation of Business Case

Project owners complete business cases for proposed projects that include: business needs or issues to be addressed, risks/opportunities, alternatives, and proposed solution. Customer engagement and preferences are used to help inform asset management planning decisions. This is described in greater detail in Section 3.2.1. Business cases also include other project specific parameters such as: scope of work, cash flows, key milestone dates, and risk results. Business cases must also ensure that the project conforms to company standard pricing, economic justification, and follow established engineering specifications, in relation to design, construction, safety, and method of installation. Depending on the size of the project, Enbridge Gas may need to file a Leave to Construct application with the Board to determine if the project can be built.

Economic Analysis

Economic analysis of system expansion projects is completed using a Discounted Cash Flow ("DCF") method. E.B.O. 188 and E.B.O. 134 describe the parameters and methodology for the DCF.

1. E.B.O. 188 describes the economic test that should be used to evaluate a proposed expansion of a gas distribution system.
2. E.B.O. 134 describes the economic test that should be used to evaluate a proposed expansion of a gas transmission system.

Business Case Review and Portfolio Optimization

Upon completion of the economic analysis of a project, business cases are brought forward for review and approval, and prioritization/optimization by the Asset Management group, in conjunction with Finance and Regulatory.

Consolidation and Management Review and Approval

Capitalized overheads are added to the consolidated capital budget and the overall capital budget is reviewed within Finance to ensure that the budget is consistent with company targets and objectives, as well as to ensure compliance with capitalization policies and accounting standards. This ensures that only costs which are capital in nature are included within the capital budget. The consolidated capital budget is then presented to management for approval. It is subsequently consolidated by Finance with the broader Company budget, and is reviewed and approved by the Company's senior executive management team.

3.1.5 Full Budget Approval

Once all of the components of the budget are reviewed by their respective accountable Vice President, the overall budget and LRP is consolidated to provide leadership with the Financial Plan for the Company. The consolidated budget and LRP is then reviewed and approved by the Company's senior executive management team.

3.2 PROJECT SELECTION AND PRIORITIZATION/OPTIMIZATION

The Asset Management process begins with the identification of a risk or need. Operational risks and needs are identified on a systematic and ongoing basis. The asset management processes are detailed in Section 4 of each respective AMP, provided at Exhibit C1, Tab 2, Schedule 1 and Exhibit C1, Tab 3, Schedule 1.

Enbridge Gas has defined risk tolerances and uses a risk framework that includes risk matrices to inform capital investments. Although the framework is consistent, the approach used to assess risk is different between the historical EGD and Union asset management processes. EGD uses a primarily quantitative approach calculating the current state risk and the post solution risk, while Union uses a more qualitative approach and assesses the current state risk.

Both organizations have forecasted a 10-year capital investment plan (for both expansion and maintenance capital initiatives), where the risk is used for prioritization/optimization. For EGD, the capital plan is based on optimization using Lifetime Risk Return on Investment, which maximizes risk mitigation based on capital investment. For Union, the capital plan is based on a prioritization and risk ranking methodology. Risks above a specific threshold are addressed within the constraints of the capital budget. A considerable portion of spend is driven by mandatory initiatives involving compliance related work and addressing intolerable risks or risks that require a solution within a defined time. High risk projects may trigger reprioritization of lower risk projects or may result in a request for incremental funding.

The respective asset management processes are used for selecting and prioritizing/optimizing core business investments. Despite their opportunities being evaluated using the same investment valuation framework, opportunities outside of core business activities that have different funding mechanisms and are driven and supported through public and governmental policies/regulations do not flow through this process (such as Community Expansion, renewable natural gas, etc.).

3.2.1 Customer Needs and Overall System Planning Policy Objectives

An important part of the asset planning process is the inclusion of customer needs (or interests) and preferences into the analysis of alternatives, pacing and prioritization/optimization of capital plans. Enbridge Gas has taken a number of steps to gather information on customer needs and preferences and includes this information into the planning process.

To ensure that Enbridge Gas is engaging its customers to understand their needs and preferences and to demonstrate understanding of them, Enbridge Gas has taken steps to gather information on its customers' interests and preferences. In addition to Enbridge Gas's robust ongoing market research program, EGD and Union engaged consultants to gather valuable feedback from their customers through the use of surveys and focus groups. Questions ranged from enquiries related to the customers' willingness to support, through their rates, the expansion of renewable natural gas to questions relating to customer preferences and desired outcomes. The results of this customer engagement inform Enbridge Gas's approach to its long-term plans.

Based on this engagement, Enbridge Gas has identified that customers of both utilities are satisfied with the service they are receiving from their natural gas service providers. Through this customer engagement process the top three most important outcomes for its customers are price, safety and reliability. Both EGD and Union found that there is customer willingness to pay for investments to ensure that the system remains healthy in the long term. Section 2.4 of the AMPs provides additional information on the customer engagement process and results. This consultation with customers complements a well-established market research program that includes regular customer satisfaction surveys for all markets.

The customer engagement work revealed a common theme among customers that environmental stewardship is an important outcome. In some cases, customers indicated that they are willing to pay more for projects aimed at reducing environmental impact. Enbridge Gas is committed to finding ways to continuously improve its environmental performance as well as providing solutions to customers to help them reduce their environmental impact. Projects and programs related to renewable natural gas as well as reductions of greenhouse gas emissions and other pollutants from Enbridge Gas facilities are being advanced to reflect customer preferences and ensure compliance with existing regulations and in anticipation of new federal regulations.

Integrated Resource Planning

Enbridge Gas is committed to providing consumers access to safe, reliable and affordable natural gas services. Enbridge Gas is also committed to its role in offering balanced solutions that support emission reduction targets, including: (i) energy savings information that enables consumers to optimize their energy consumption; (ii) a portfolio of OEB-approved energy conservation programs to facilitate transparent and measurable conservation; and, (iii) development and testing of low-carbon technology solutions.

As part of its Decision on the Utilities' Demand Side Management ("DSM") 2015-2020 DSM Plans (EB-2015-0029,-0049) the OEB directed the Utilities to work jointly on a transition plan to incorporate DSM into the Utilities' infrastructure planning activities and to file an Integrated Resource Planning ("IRP") Transition Plan (the "Transition Plan") as part of the 2015-2020 DSM Mid-Term Review. The Utilities provided the Transition Plan along with an executive summary of the associated IRP Study conducted by ICF International, as part of their respective Mid-Term Review submissions and presentations.[5] As noted in the Transition Plan, the IRP Study and by the Utilities, the current OEB-approved 2015-2020 DSM Plans are focused on achieving broad-based annual savings (including avoided distribution costs), whereas infrastructure planning is focused on safely and reliably meeting a long-term peak-hour design forecast.[6] As noted in the Transition Plan, the current in-field case studies being completed in the

[5] The Transition Plan defines IRP as a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply-side and demand-side options to determine the least cost and lowest risk approach in addressing transmission and distribution infrastructure requirements.
[6] The impact of broad-based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of historical DSM measures, as well as other natural conservation factors such as improved building codes and higher energy efficiency standards for natural gas equipment.

market by the Utilities will provide a better understanding of the impacts of broad-based DSM programs and technologies on peak-hour demand.

Accordingly, Enbridge Gas expects that the Transition Plan will be refined in the future to reflect: (i) additional OEB guidance required to facilitate IRP including the appropriate scope of IRP analysis and regulatory policy-related issues raised in the IRP Study; and, (ii) the impact of DSM, low-carbon and carbon reducing programs on peak-hour demand.[7] Recognizing there are still scope and policy issues to be addressed, IRP will continue to be monitored as part of EGD's and Union's AMPs to ensure advancements made are acknowledged and incorporated during asset investment planning.

3.2.2 Linkages and trade-offs between capital projects and ongoing O&M spending

In developing the asset management plans, Enbridge Gas considers ongoing O&M expenses and capital investments. In many cases it may be possible to continue to spend O&M dollars to extend an asset's useful life. However, as the condition of the asset degrades over time, O&M expenditures increase to the point that there is no economic benefit to continuing to operate the asset and renewal investment becomes the preferred option.

[7] IRP could include: energy efficiency, behind-the-meter and low-carbon solutions (e.g. natural gas heat pumps), distributed energy resources (e.g. CNG, RNG, hydrogen), the interplay of IRP options to optimize energy consumption and impact system demand.

In general, Enbridge Gas's maintenance programs involve the expenditure of O&M dollars to complete inspections and repairs to maintain the required function of the assets. When it either becomes impossible or no longer cost-effective to continue to manage the assets in this fashion, capital renewal investment may be required to replace the asset or restore its function to its required level. Both EGD and Union have integrity management programs. These programs include O&M expenditures to perform inspections on the assets. The inspections have three possible outcomes:

1. no further action required as the health of the asset is deemed acceptable for continued service until the next inspection;
2. a repair is required which will be addressed with O&M expenditures; or,
3. some form of replacement or renewal is required that will require capital investment.

Risk tolerance is a factor in determining the appropriate time to make an investment to renew or replace an asset. Using the Risk Management processes outlined in the AMPs, risks are identified and solutions are planned to achieve a risk reduction, balanced against the costs required to manage the risk.

4.0 Capital Investment Plan

4.1 Engineering Plan

Enbridge Gas's engineering plan is represented by the respective AMPs, which are provided at Exhibit C1, Tab 2, Schedule 1 and Exhibit C1, Tab 3, Schedule 1. The purpose of Enbridge Gas's engineering plan is to provide the Board and its stakeholders with the supporting background and view of the company's forecast of capital expenditures over a ten-year period. These plans are underpinned by an assessment of asset condition, system health and the risks associated with individual asset categories or classes.

Enbridge Gas gathers information through different means to inform its decisions. The work management and asset management systems gather key observations from inspection orders completed by frontline technical resources. Data is also derived from asset data systems and on-line data sources such as the Geographic Information System, SCADA, and compressor data packages. The data from these various sources is then analyzed to identify trends and issues related to asset condition; for some assets, data can be combined with tacit knowledge to inform decision making. This may result in the need for revised maintenance attention through operating expense activities or capital renewals.

Section 3.2 details how the investments outlined in the engineering plan are identified and analyzed. These methods range from a qualitative risk assessment process used by Union to a more quantitative risk assessment approach employed at EGD. The risk assessment processes are described in Section 4 of the respective AMPs. Both processes are underpinned by data. The information and analysis that is derived from the data are used to help support business cases for the items that compose the ten-year engineering plan.

In both the EGD and Union AMPs, Section 5 details the engineering plan by asset category or class and Section 6 further outlines the resultant capital expenditure requirements.

4.2 Investment Categories

EGD and Union have unique investment categories. These categories have been mapped in Table 2 to the four general investment categories outlined in Chapter 5 of the Filing Requirements for Electricity Applications. The description of each investment category is as follows:

System access investments are additions and modifications (including asset relocation) to a distributor's system that a distributor is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution system.

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's system to provide customers with natural gas services.

System service investments are modifications to a distributor's system to ensure the system continues to meet distributor operational objectives.

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its commodity-carrying system including land and buildings, tools and equipment, fleet vehicle and electronic devices and software used to support day to day business and operations activities.

Table 2
Investment Categories

	Map to EGD AMP/USP	Map to Union AMP/USP
System Access	Apartment Ensuite – New Construction Apartment Traditional – New Construction Commercial – New Construction Industrial – New Construction Residential – New Construction Apartment Ensuite - Replacement Apartment Traditional – Replacement Commercial – Replacement Industrial – Replacement Residential – Replacement Sales Station – New Meters – Capital Purchase Program NGV Community Expansion Rebillable Relocations	CNG Community Expansion General Customer Growth Municipal Replacement
System Renewal	Main Replacement Service Relay Integrity Retrofit – Pipe Integrity Digs – Pipe Corrosion Prevention Non-Rebillable Relocations Gate & Feeder Stations Station Rebuild Inside Regulator Program Integrity Digs – Storage Integrity Retrofit – Storage Measurement and Regulating Equipment – Storage Compressor Equipment Field Lines Wells and Well Equipment Regulator Refit Remediation – Customer Assets	Bare and Unprotected Steel Cathodic Protection Compression Equipment Compressor Overhauls Excess Flow Valves General Mains Integrity Management Program Leakage LNG Capital Maintenance Measurement Electronics Upgrades Measurement Upgrade Meter Exchange Program Replacement of Vaulted Stations Service Replacement Station Painting Stations Capital Maintenance Storage Integrity Vintage Pipeline Replacement

	Meters – Capital Purchase Program	General Pipeline Maintenance
System Service	Carbon Capture MOP Records Integrity – Pipe Integrity Initiatives – Pipe Integrity Initiatives – Stations Records Integrity – Stations Integrity Initiatives – Storage Records Integrity – Storage Integrity Survey – Customer Assets Records Integrity – Customer Assets System Monitoring System Reinforcement – Pipe System Reinforcement – Stations	Class Location Compressor and Dehy Capital Maintenance Depth of Cover <30% SMYS Depth of Cover >30% SMYS Distribution Reinforcement Emissions Action Plan Excess Flow Valves General Mains In-Franchise Growth LNG Capital Maintenance Measurement Electronics Upgrades Measurement Upgrades MOP Verification Odourant Upgrade Station Reinforcement Storage Improvements Storage Integrity System Growth Transmission Reinforcement General Safety Integrated Resource Planning
General Plant	Land – Storage Structures and Improvements - Storage Capital Purchase Program – Equipment & Materials Capital Purchase Program – Vehicles Capital Purchase Program – Tools IT Implementation Furniture/Structure & Improvements Leasehold Improvements	Compressor and Dehy Capital Maintenance Fleet IT Technologies Land Rights LNG Capital Maintenance Measurement Electronics Upgrades Other – Indirect Materials Service Facilities Tools

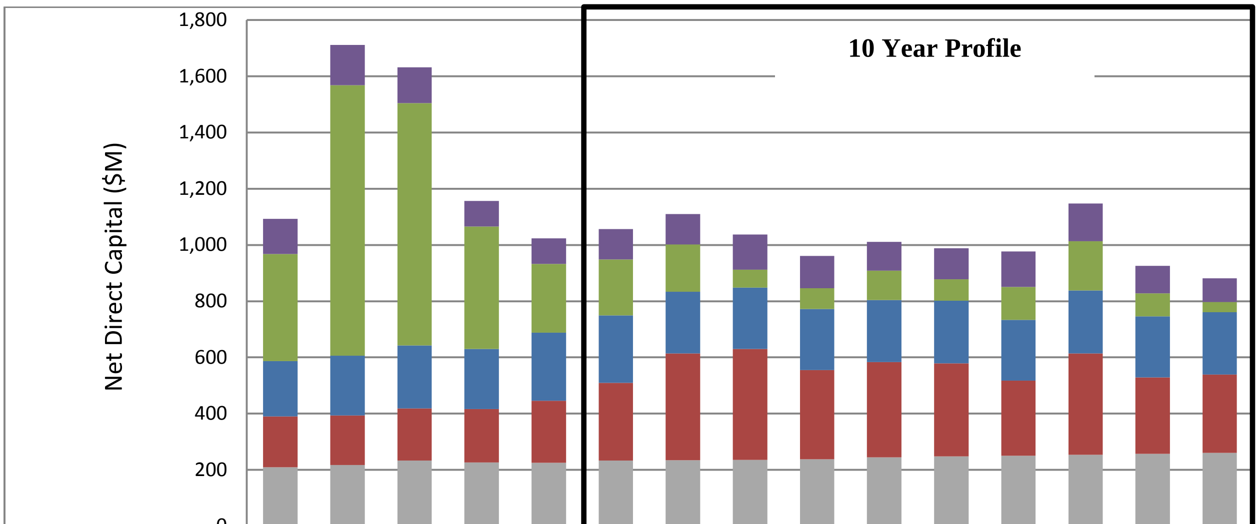
4.3 CAPITAL EXPENDITURE SUMMARY

Enbridge Gas’s total historical and total forecasted ten year spend profile by investment category is illustrated in Figure 6. Enbridge Gas’s projected spend totals $5.18 billion and $10.1 billion over the next five and ten years; the projected annual spend ranges between $881 million to $1.14 billion within the ten year profile. System Renewal and System Access are Enbridge Gas's highest asset investment categories at $3.21 billion and $2.22 billion over the ten years, respectively. This capital spend profile supports customer growth and reinforcement expenditures that will support the addition of new customers, as well as expenditures associated with existing assets to maintain safe and reliable business operations.

The capital expenditure is the result of applying EGD and Union's asset management processes and principles to address:

- Asset needs as outlined in each respective AMP;
- Known compliance requirements;
- Identified risks within EGD or Union's intolerable risk region; and
- Identified risks requiring a solution within a defined time window.

Figure 6
Enbridge Gas's Capital Expenditure



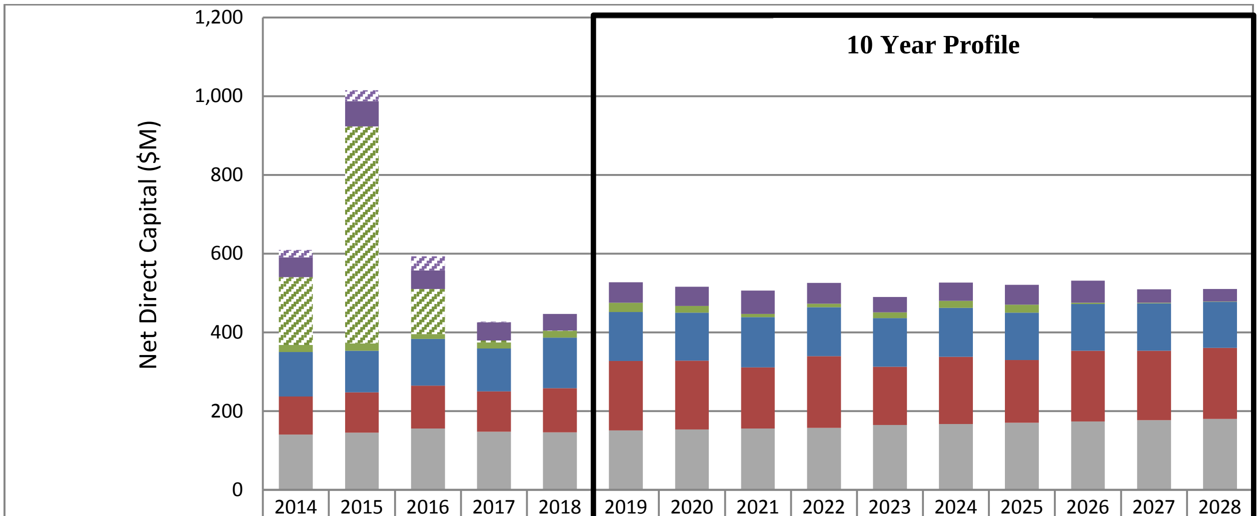
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
General Plant	125	143	127	91	91	108	109	125	115	103	111	127	134	99	83
System Service	381	961	862	436	245	199	168	63	74	104	76	117	175	81	37
System Access	197	213	224	213	242	239	219	219	217	221	223	216	225	218	221
System Renewal	180	176	185	190	220	277	381	393	317	338	331	266	360	271	279
Overhead	210	217	234	227	226	233	234	236	238	245	248	251	254	257	260
ENBRIDGE GAS Total	1,093	1,711	1,632	1,157	1,023	1,056	1,110	1,037	961	1,011	988	977	1,147	926	881

EGD's component of Enbridge Gas's capital expenditure profile is presented in Figure 7.[8]

EGD's projected spend remains at a consistent level and totals \$2.57 billion and \$5.17 billion over the five and ten years, respectively. Historical spend for the System Service and General Plant investment categories are higher than projected due to large one-time initiatives approved through separate Board approvals that have taken place, such as EGD's GTA and WAMS projects. The slight increase in overall spend compared to recent years is due to the heightened understanding of asset management needs and resultant life cycle strategies.

[8] Projects that are still under development are not currently included in EGD's spend profile. For details refer to Section 6 of EGD's AMP.

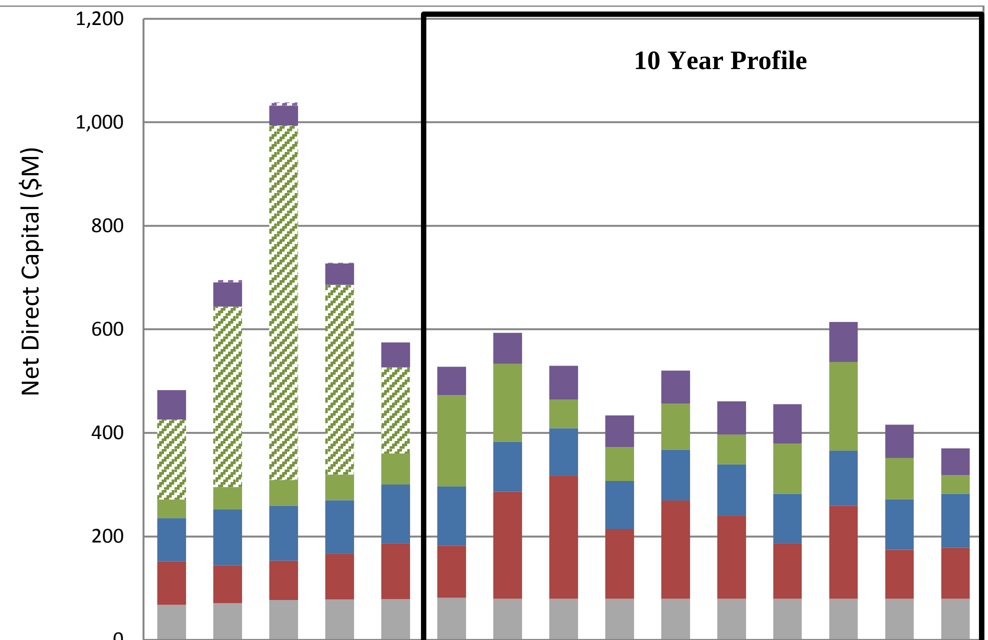
Figure 7
EGD's Capital Expenditure



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
General Plant (WAMS)	19	28	36	2											
General Plant	50	64	47	46	43	52	49	59	53	39	46	51	56	34	31
System Service (GTA)	172	551	115	5	0										
System Service	18	19	12	15	18	23	17	9	9	14	18	20	4	2	1
System Access	113	105	118	109	128	125	122	127	124	124	124	121	118	120	117
System Renewal	97	103	109	102	112	176	174	155	182	148	171	159	180	177	181
Overhead	141	146	156	148	147	151	154	156	158	165	168	171	174	177	180
EGD Total	610	1,015	593	428	448	528	517	507	526	491	527	522	532	510	510

Union's component of Enbridge Gas's capital expenditure profile is presented in Figure 8. Union's projected spend totals $2.61 billion and $4.93 billion over the five and ten years, respectively. The spend profile for 2014 through the end of 2017 and the significant increase in the system service category is primarily driven by a period of unprecedented growth on the Dawn-Parkway System. Through 2018 and 2019 continued elevated levels of investment in the system service category are driven by both the Sudbury Replacement project as well as the Kingsville Reinforcement project. In 2020 and 2021 there are two large proposed renewal projects to replace vintage steel pipelines.

Figure 8
Union's Capital Expenditure



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
General Plant (Service Facilities Dawn)	0	4	6	1											
General Plant	57	47	39	41	48	55	60	66	61	63	64	76	77	64	52
System Service (BOP, Dawn, Panhandle, Sudbury)	155	349	685	366	166										
System Service	36	43	50	50	60	176	151	55	65	90	58	97	171	80	36
System Access	84	108	106	104	114	115	96	92	93	97	99	95	106	98	104
System Renewal	84	73	76	88	108	100	206	238	135	190	161	108	180	94	98
Overhead	68	72	77	79	79	82	80	80	80	80	80	80	80	80	80
UNION Total	483	695	1,038	729	575	528	593	530	434	520	461	456	615	416	370

For further breakdown and explanation of EGD and Union’s spend profiles, refer to Section 6 of each Asset Management Plan.

5.0 ASSET MANAGEMENT PLANS

The AMPs for EGD and Union have been filed separately as part of this Enbridge Gas USP (Exhibit C1, Tab 2, Schedule 1 and Exhibit C1, Tab 3, Schedule 1).

5.1 DESCRIPTION OF PLANS

Scope

Both AMPs cover all regulated assets inclusive of commodity-carrying assets directly related to the task of transporting natural gas from the source to the end-use customer and real estate, fleet and IT assets that support business operation.

Through the AMPs and respective processes, investment opportunities and alternatives are evaluated to determine the expenditure of capital funding. Both organizations have created a 10-year forecast of capital investments for expansion and maintenance capital.

Asset Categorization

Asset categories are used by both EGD and Union to organize and define assets in the respective AMPs. Table 3 aligns these asset categories between EGD and Union

Table 3
Asset Categorization Alignment between Union and EGD

/u

Union	EGD
Pipelines	Pipe
Stations	Stations
Distribution / System Growth	Customer Growth
Measurement	*Contained within Storage, Stations, Customer Assets Asset Classes*
Contained within pipelines, stations, measurement asset categories	Customer Assets
Utilization	*Contained within Customer Assets Asset Classes*
Underground Storage	Storage
Compression and dehydration	*Contained within Storage Asset Class*
Liquid Natural Gas (LNG)	n/a
Corporate Real Estate (CRES)	Real Estate and Workplace Services
Fleet	Fleet and Equipment
Information Technology (IT)	TIS (Technology Information Services)
n/a	Business Development

Risk Framework

Both organizations use a risk framework that includes risk matrices to inform capital investments; however, the frameworks are different:

EGD: Uses a Quantitative Risk Assessment methodology that quantifies the risk based on likelihood and consequence. The pre-solution and post-solution risk is calculated to determine the risk mitigation associated with the capital investment.

Union: Uses a qualitative approach to assessing the risks in accordance with a 5x5 matrix by determining the consequence and likelihood. These risks are discussed and assessed through a process of risk ranking sessions with subject matter experts from various areas in engineering and operations.

In addition, both organizations have defined risk tolerances:

EGD: Uses a Quantitative Risk Assessment methodology that quantifies the risk based on likelihood and consequence. The pre-solution and post-solution risk is calculated to determine the risk mitigation associated with the capital investment.

EGD: defines risk tolerances for Health and Safety Risk, Customer Satisfaction Risk, and Financial Risk – these three risk dimensions are summed to determine total risk, however, there is no defined threshold for total risk.

Union: defines risk tolerance based on total risk.

Selection & Prioritization/Optimization Process

To form the capital investment plan, both organizations use an understanding of risk to drive the selection and prioritization/optimization process:

EGD: The capital plan is based on an optimization using Lifetime Risk Return on Investment. This optimization maximizes Risk Mitigation based on capital investment.

Union: The capital plan is based on prioritization and risk ranking.

The capital expenditure is the result of applying EGD's and Union's asset management processes and principles to address:

- Asset needs as outlined in each respective AMP;
- Known compliance requirements;
- Identified risks within EGD's or Union's intolerable risk region;
- Identified risks requiring a solution within a defined time window.

Document Structure

As outlined in Table 4 below, the structure of both EGD's and Union's AMPs are aligned:

Table 4
Asset Management Plan Document Structure Alignment between EGD and Union

Union	EGD
Section 1: Executive Summary	Section 1: Executive Summary
Section 2: Background and Objectives	Section 2: Introduction
Section 3: Asset Management Framework	Section 3: Asset Management Framework
Section 4: Strategy and Planning	Section 4: Strategy and Planning
Section 5: Customers and Assets	Section 5: Customers and Assets
Section 6: Summary of Capital and Incremental O&M Expenditures	Section 6: Summary of Capital Expenditures
Appendices (A-D)	Section 7: Appendix

5.2 ALIGNMENT OF ASSET MANAGEMENT PLANS TO THE CHAPTER 5 REQUIREMENTS

The AMPs were built using guidance from the OEB's filing requirements for natural gas distributors. Further guidance was obtained through the more detailed Chapter 5 of the filing requirements for electric distributors. Table 5 provides the alignment of sections that comprise each of EGD's and Union's AMPs to the Chapter 5 requirements.

Table 5
Alignment of EGD and Union's Asset Management Plan Sections with the OEB's Filing Requirements

Chapter 5 - Filing Requirements (OEB)	EGD AMP Section Reference	Union AMP Section Reference
5.2.1 Distribution System Plan overview	Section 2: Introduction	Section 2: Background and Objectives Section 3.2.1 The IMS and Continual Improvement
5.2.2 Coordinated planning with third parties	Section 2.4: Stakeholder Commitment	Section 2.4: Stakeholder Commitment
5.2.3 Performance measurement for continuous improvement	Section 4.2.5: Performance Measurement	Section 3.2.1: The IMS and Continual Improvement
5.2.4 Realized efficiencies due to smart meters	N/A	N/A
5.3.1 Asset management process overview	Section 3: Asset Management Framework Section 4: Strategy & Planning	Section 3: Asset Management Framework Section 4: Strategy & Planning
5.3.2 Overview of assets managed	Section 5: Customers & Assets (*by asset class*)	Section 5: Customers & Assets (*by asset class*)
5.3.3 Asset lifecycle optimization policies and practices	Section 5: Customers & Assets (by asset class)	Section 4: Strategy & Planning
5.3.4 System capability assessment for renewable	Section 3.5: Integrated Resource Planning	Section 4.2.1.2.1: Integrated Resource Planning

energy generation	Section 5.9: Business Development	Section 4.3: Facility Greenhouse Gas (GHG) Abatement Section 5.2.3: Growth – Other (RNG, CNG, LNG)
5.4.1 Capital expenditure planning process overview	Section 3: Asset Management Framework Section 4: Strategy & Planning Section 6: Capital Expenditure	Section 3: Asset Management Framework Section 4: Strategy and Planning Section 4.2.1.1.3: Risk Management Section 4.2.1.1.4: Project Prioritization and Selection Section 4.2.1.2.1: Integrated Resource Planning Section 6: Summary of Capital and Incremental O&M Expenditures
5.4.2 Capital expenditure summary	Section 6: Capital Expenditure Summary	Section 6: Summary of Capital and Incremental O&M Expenditures
5.4.3 Justifying capital expenditures	Section 3: Asset Management Framework Section 4: Strategy & Planning Section 5: Customers & Assets (by asset class) Section 6: Capital Expenditure	Section 3: Asset Management Framework Section 4: Strategy & Planning Section 6: Summary of Capital and Incremental O&M Expenditures

5.3 Base Spend and Incremental Investments

Base spend represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation. This spend is driven by asset class strategies and program work that has sufficient risk and/or history to warrant continuation and is supported by existing rates (either through depreciation expense, annual Price Cap Index ("PCI") rate increases or increased revenues from customer growth).

Incremental investments are discrete, needed investments that are not supported by existing rates. The total spend includes all capital costs associated with the identified project (including multi-year spend that falls outside of the project's in-service year when the ICM is to be requested). Some examples include:

- Reinforcement projects needed to provide supply to a significant part of the franchise/customer area and cannot be constructed economically without a rate adjustment (e.g. Kingsville, Dawn-Parkway);
- Maintenance Projects of significant scope, that are outside the base upon which rates were based, and cannot be accommodated through a re-prioritization of other capital spending (e.g. Dawn C Plant Replacement, Windsor Line Replacement, SCOR Meter Area upgrade);
- Significant Real Estate investments (e.g. SMOC/Coventry facility consolidation).

5.4 Potential ICM Projects

Using the description of base spend versus incremental investment outlined in Section 5.3, the projects and the total in-service capital for which ICM treatment may be proposed are identified in Table 6.

Table 6
Potential ICM Projects

EGD/Union	Asset Class	Investment Category	Project Name	In Service Year	Total In-Service Capital 2019-2023 ($M)[9]
EGD	Pipe	System Renewal	NPS 30 Don River Replacement	2019	$35.4
EGD	Pipe	System Renewal	NPS 20 Don River Relocation	2020	$49.7
EGD	Storage	System Renewal	SCOR: Meter Area - Upgrade	2020 | 2021	$60.8
EGD	Pipe	System Renewal	NPS 12 St. Laurent Ottawa North Main Replacement	2022	$72.1
Union	Distribution Growth	System Service	Stratford Reinforcement	2019	$28.6
Union	Distribution Growth	System Service	Owen Sound Reinforcement	2020	$63.4
Union	Distribution Growth	System Service	Sudbury Lateral Replacement[10]	2018	$95.5
Union	Distribution Growth	System Service	Kingsville Transmission Reinforcement Project	2019	$121.6
Union	System Growth	System Service	Sarnia Industrial System	2020	$74.5
Union	Pipelines	System Renewal	Windsor Line	2020	$101.8
Union	Distribution Growth	System Service	Dunnville Line Reinforcement	2021	$12.7
Union	Distribution Growth	System Renewal	Waubuno	2021	$21.2
Union	Compression and Dehy	System Renewal	London Lines	2021	$131.1
Union	Pipelines	System Service	Byron Transmission Station Reinforcement	2022	$17.9

[9] Includes overheads.

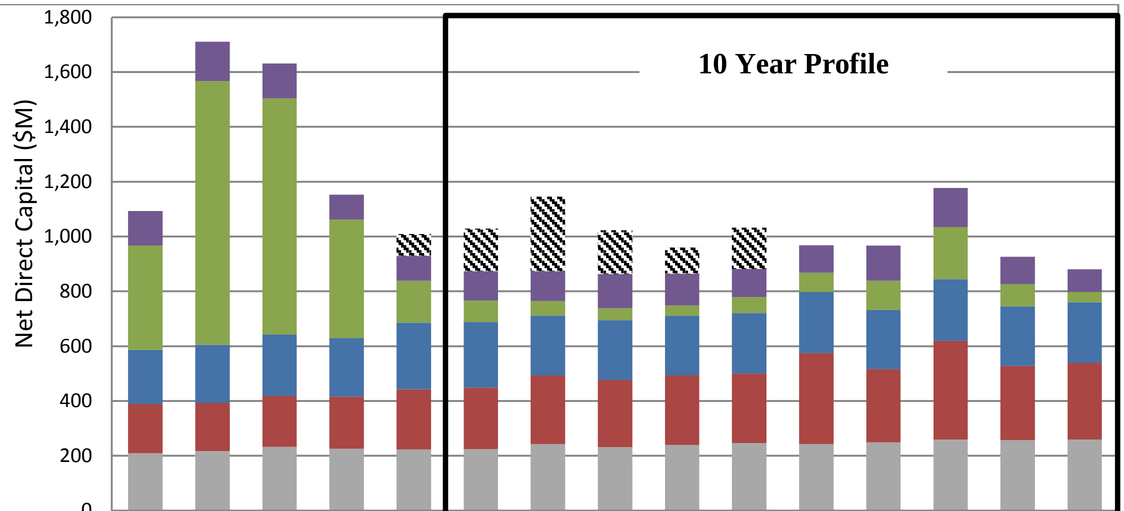
[10] Although the Sudbury Replacement Project went into service in late 2018, Enbridge Gas is requesting ICM funding for the project. Due to timing of the in-service date of this project it falls between incremental rate treatment under Union's 2014-2018 capital pass through mechanism, and incremental rate treatment under the ICM. The full year revenue requirement meets the capital pass through criteria, but there was not a full year in-service in 2018. However, the pipeline needed to be replaced in order to continue to maintain safe and reliable service to the Sudbury market. Delaying the Leave to Construct application and construction in order to confirm the funding mechanism for the project was simply not an option. If the project was delayed, integrity concerns could have become more serious, with the risk of a potential failure increasing over time.

Union	Distribution Growth	System Service	Hamilton Gate	2022	$31.1
Union	Distribution Growth	System Service	Parry Sound Reinforcement	2023	$17.3
Union	Distribution Growth	System Service	Sudbury Compression Station	2023	$35.9
Union	Distribution Growth	System Renewal	Obsolete RB211-24A C Plant	2023	$117.5

Using the capital expenditure summary presented in Section 4, the total in-service capital required for identified ICM projects between the years 2019 to 2023 is illustrated by the hatched bars; all other base spend is represented as part of the appropriate investment category (see Figure 9, Figure 10 and Figure 11)[11]. Refer to the respective AMP for more details regarding the condition and strategies driving the need for these projects requiring significant investment.

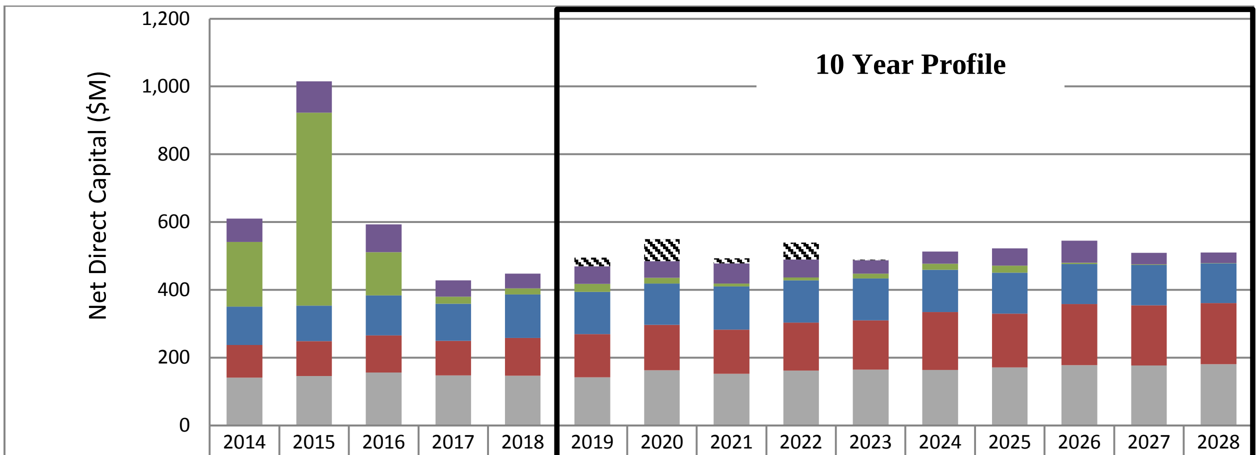
[11] ICM project spend in Figure 9, Figure 10 and Figure 11 represents the total in-service capital required for the project (excluding overheads), compared to Figure 6, Figure 7 and Figure 8 in Section 4.3 where the capital expenditure profile represents the annual cash flow (which includes required preliminary and post spend for ICM projects). Details for Enbridge Gas's request for ICM funding can be found in Exhibit B1, Tab 2, Schedule 1.

Figure 9
Enbridge Gas's Capital Expenditure Summary
(with proposed ICM project in-service spend identified from 2019-2023)



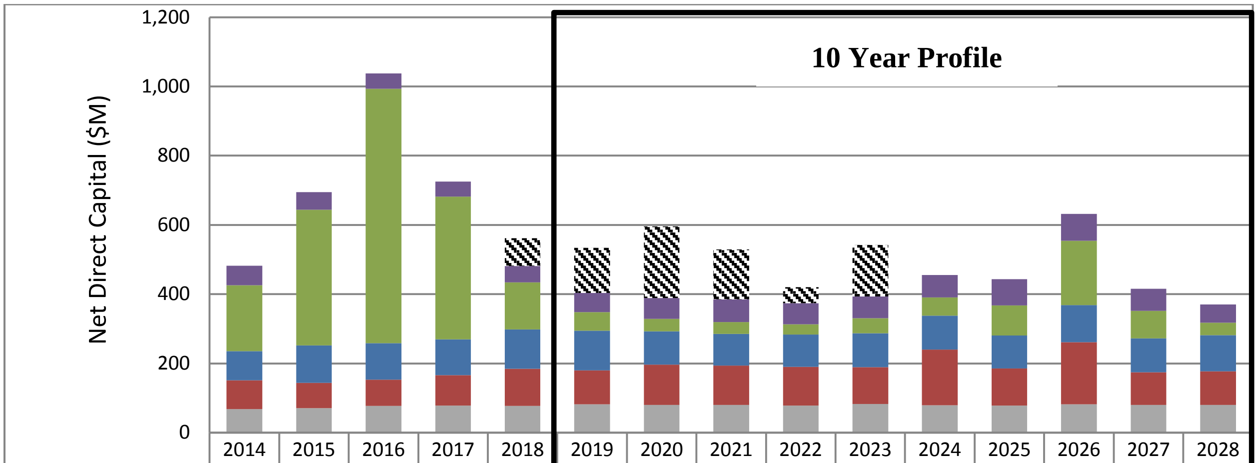
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Projects					80	155	272	160	95	151					
General Plant	125	143	127	91	91	108	109	125	115	103	101	128	143	99	83
System Service	381	961	861	432	153	78	53	43	38	58	71	107	190	81	37
System Access	197	213	224	213	242	239	219	219	217	221	223	216	225	218	221
System Renewal	180	176	185	190	220	225	250	244	254	252	332	266	360	271	279
Overhead	210	217	234	227	224	225	244	232	240	248	243	250	260	257	260
ENBRIDGE GAS Total	1,093	1,710	1,632	1,153	1,009	1,029	1,146	1,024	960	1,032	969	967	1,177	926	881

Figure 10
EGD's Capital Expenditure Summary
(with proposed ICM project in-service spend identified from 2019-2023)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Projects						25	65	16	50	2					
General Plant	69	92	83	48	43	52	49	59	53	39	36	52	65	34	31
System Service	190	570	127	20	18	23	17	9	9	14	18	20	4	2	1
System Access	113	105	118	109	128	125	122	127	124	124	124	121	118	120	117
System Renewal	97	103	109	102	112	127	133	131	142	145	171	159	180	177	181
Overhead	141	146	156	148	147	142	163	152	162	165	164	171	178	177	180
EGD Total	610	1,015	593	428	448	495	550	494	540	490	513	523	545	510	510

Figure 11
Union's Capital Expenditure Summary
(with proposed ICM project in-service spend identified from 2019-2023)



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Projects					80	130	207	145	46	148					
General Plant	57	51	45	43	48	55	60	66	61	63	64	76	77	64	52
System Service	190	391	734	412	135	54	36	34	30	43	53	87	186	80	36
System Access	84	108	106	104	114	115	96	92	93	97	99	95	106	98	104
System Renewal	84	73	76	88	108	97	116	114	112	107	161	108	180	94	98
Overhead	68	72	77	79	77	82	80	80	78	83	79	78	82	80	80
UNION Total	483	695	1,038	725	562	534	596	530	420	542	456	444	632	416	370

6.0 BENCHMARKING

Another way EGD and Union have historically sought to continually improve is through industry engagement. Key subject matter experts involved in the design and operations of assets are engaged in industry related code committees and industry best practice committees to better understand compliance requirements, to support the improvement of codes and standards that drive operational safety, and to learn and share best practices from industry peers. Examples include active membership of subcommittees for the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems, Canadian Gas Association ("CGA") and American Gas Association ("AGA") surveys and workshops and participation in AGA peer reviews.

7.0 OTHER

7.1 PROJECTS/PROGRAMS SUBJECT TO LEAVE TO CONSTRUCT

In constructing hydrocarbon pipelines, Enbridge Gas follows the guidelines prescribed in the OEB Act. The guidelines require a leave of the OEB prior to constructing a hydrocarbon pipeline project subject to the following criteria:

1. the proposed hydrocarbon pipeline is more than 20 km in length;
2. is projected to cost more than the amount prescribed by the regulations (presently $2 million);
3. any part of the proposed hydrocarbon line (i) uses pipe that has a nominal pipe size of 12 inches or more, and (ii) has an operating pressure of 2,000 kilopascals or more; and,
4. Criteria prescribed by the regulations are met 2003, c.3, s. 63(1).

7.2 PROJECTS/PROGRAMS NOT SUBJECT TO LEAVE TO CONSTRUCT ("LTC")

Construction projects may not require approval from the OEB prior to construction in the following circumstances:

1. the project does not meet the leave to construct criteria prescribed in the OEB Act;
2. the project falls under federal jurisdiction that requires approval from the National Energy Board; or,
3. the project involves relocation or reconstruction of an existing pipeline, unless the size of the line is changed or additional land is required.

7.3 Customer Additions and Profitability Index Values

Customer Connections Feasibility

Enbridge Gas expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. These guidelines are articulated in the E.B.O. 188 report. [12] The intent of E.B.O. 188 is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

For the general service market, Enbridge Gas uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage distribution system expansion activities and ensures that required profitability standards are achieved at both the individual project and the portfolio level.

If the expansion is driven by large commercial/industrial customers (contract market), the feasibility analysis factors in the individual contribution of the customer to the project and assesses whether the customer would be asked to pay a Contribution in Aid of Construction ("CIAC"). This is explained in more detail below.

Investment Portfolio

This approach evaluates feasibility on all proposed new distribution customer attachments for a particular year and ensures required portfolio profitability index ("PI") achieves the required

[12] E.B.O. 188 Final Report of the Board, January 30, 1998.

thresholds. The portfolio includes the costs and revenues associated with all new distribution customers forecast to be attached in a particular year, including new customers attaching to existing main or infill services. It also ensures there is no undue cross-subsidization in the short term. The investment portfolio is designed to achieve a PI threshold greater than 1.0.

Rolling Project Portfolio ("RPP")

This approach maintains a portfolio of distribution system expansion projects over a rolling 12-month period. RPP is used as a management tool for estimating future impacts of capital expenditures associated with system expansion. RPP excludes customers attaching to existing mains, which is also known as infill services. RPP is required to achieve a PI threshold greater than 1.0.

The figures below show the historical PI for the investment and RPP for both EGD and Union.

Figure 12

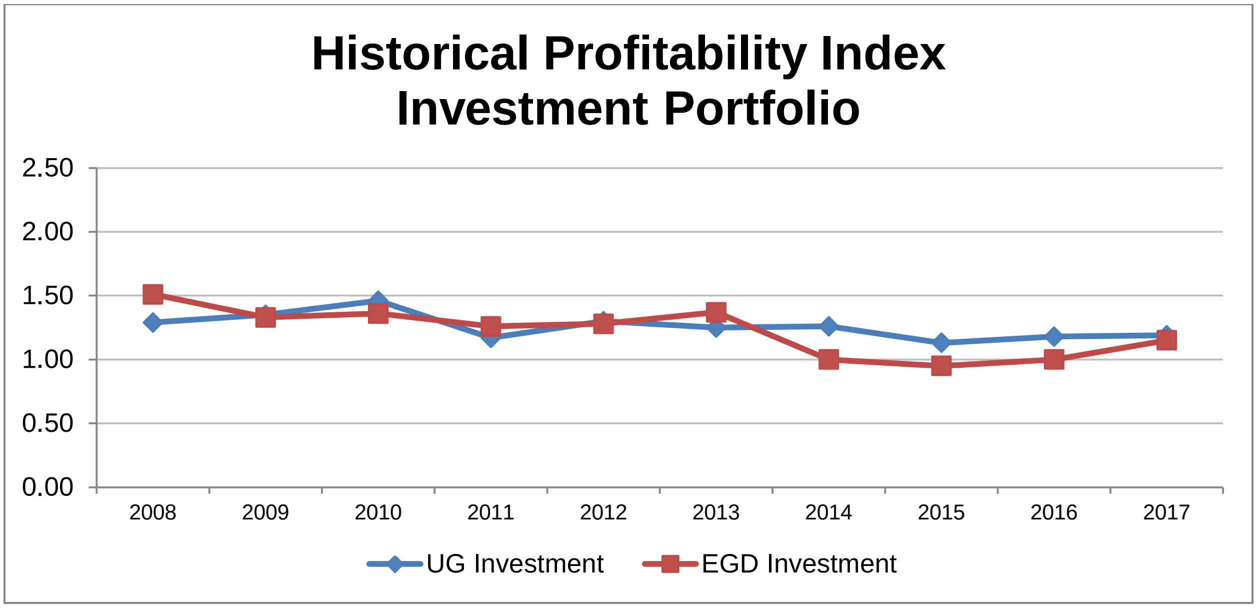
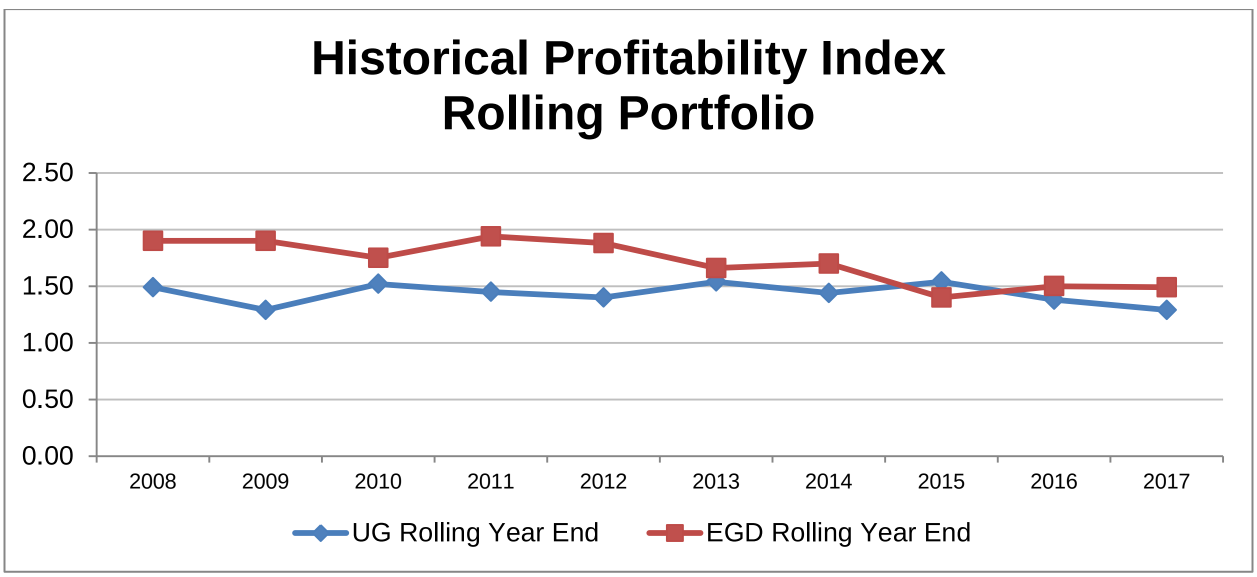


Figure 13



Feasibility Process

When evaluating a new project, the Company prepares a forecast of project costs and revenues. An Enbridge Gas field representative visits the project site to determine the project requirements and costs, number of potential customers, and the anticipated natural gas consumption. Project revenues are calculated based on the estimated number of new customers and their estimated annual natural gas consumption over a 40-year period for heating and water heating loads and over a 20-year period for processing loads.

The Company determines project feasibility using forecast project costs and revenues - if the present value of project revenues is equal to or greater than the present value of project costs, the project is economically feasible and can proceed to be built. In such a case, over the life of the project, revenues will recover the entire cost of the project. Depending on the size of a project, the Company may file a LTC application for OEB approval. In some instances, the OEB may approve a project with the requirement that the Company meet certain conditions.

When the present value of revenues is less than the present value of costs, customers are asked to pay a CIAC amount. The CIAC is the amount the customer finances in order for the project to be feasible, that is, brought to the required PI level.

The OEB recognizes that the amount charged as a CIAC is project-specific and varies depending on the costs and revenues for each project. The OEB has established feasibility guidelines and a formula for calculating the CIAC. Utilities can only charge a CIAC as prescribed by the OEB in E.B.O. 188. If the customer chooses not to pay, the project is not built.

Feasibility Formula

$$\text{Profitability Index (PI)} = \frac{\sum PV(\text{Revenue} - \text{O\&M} + \text{CCA Tax Shield})}{\sum PV \text{ of Capital Cost}} \text{ or PI} = \frac{\text{Benefits}}{\text{Cost}}$$

Benefits

The project revenues are the monthly customer charges and delivery charges that the customer pays.

Costs

Direct capital costs for a project include materials (e.g. pipe, couplings, meter sets, etc.), labour and equipment to install or construct the project, reinstatement of the surface (such as road, sidewalk, landscaping), and the ongoing operation and maintenance of the project.

Indirect costs for a project include the costs of support groups (such as Customer Connections, Construction, Network Planning, and Land) that facilitate the connection process, gas distribution network planning costs which support new load growth, drafting activities, and administration costs attributable to customer growth such as inventory management.

Customer Growth Forecast

The customer growth forecast follows the methodology that the OEB approved for each of EGD and Union.

Several data considerations and sources are taken into account when developing the forecast such as the historical and predicted housing starts from Canadian Mortgage and Housing Corporation, Conference Board and Consensus Economics forecast.

Other considerations include information about development projects gained through direct contact with builders, developers and municipalities; historical trends of the percentage share of the provincial market and historical penetration rates.

Further detail on each individual approach is provided in the AMPs.

7.4 Projects Undertaken in Relation to Initiatives From the Minister of Energy

The communities in Ontario that remain without natural gas service are distant from existing gas distribution infrastructure, have relatively low numbers of potential consumers, and may have terrain that precipitates high construction costs. These factors have limited the ability of Ontario natural gas distributors to serve these communities, as economic feasibility requirements cannot be met.

In 2016, the OEB issued a decision in its generic proceeding on new community expansion, allowing for a System Expansion Surcharge ("SES") which generates additional revenue, enhancing the economic feasibility of community expansion projects.

The Ontario government has stated it will enact policy to assist in the development of new infrastructure to allow for natural gas service to reach rural communities and rectify energy inequities for these communities. In September 2018, the Ontario tabled Bill 32 designed to support a ratepayer funded model to help serve new communities with natural gas.
To determine which communities will be qualified for gas service expansions, the Company assesses the economic feasibility for potential expansion (using the same process used for PI calculation). To move forward with these projects, Enbridge Gas will need to be able to recover the revenue differences associated with these projects in gas distribution rates. These community expansion projects will still require the OEB's approval of the Company's LTC application, and the application of the SES. Community expansion projects are categorized under the System Access category. Refer to the respective AMPs for further details.

A number of other communities are currently being assessed for further community expansion opportunities through the application of the SES and the implementation of Bill 32.