EB-2022-0200

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(EGI – Integration Capital Panel)

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CAPITAL EXPENDITURE HISTORY

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1. The purpose of this evidence is to present a summary of capital expenditures for EGD and Union for 2013 to 2018 which includes the incentive regulation (IR) terms from 2014 to 2018 for each respective utility. This evidence also provides a summary of capital expenditures for Enbridge Gas for the deferred rebasing term and the 2024 Test Year.

2. Capital expenditures are required to ensure the ongoing safe and reliable delivery of natural gas while economically attaching new customers. Prior to amalgamation, both EGD and Union followed similar approaches in prioritizing capital expenditures under their respective IR frameworks.

3. This evidence is organized as follows:
    1. Introduction
    2. Summary of Capital Expenditures 2013 to 2018 – EGD
    3. Summary of Capital Expenditures 2013 to 2018 – Union
    4. Year-over-Year Variance Analysis of Capital Expenditures 2019 to 2024 – Enbridge Gas

1. Introduction

4. As provided at Exhibit 2, Tab 5, Schedule 1, the level of capital expenditures varies from year to year largely due to significant replacement and reinforcement projects and the timing of the execution of these projects. However, the underlying base capital expenditures were stable over the 2013 to 2018 period for both EGD and Union as well as over the deferred rebasing term for Enbridge Gas.

5. Table 1 provides a summary of the Earning Sharing Mechanism (ESM)[1] docket numbers for EGD, Union and Enbridge Gas from 2014 to 2021. Comparisons of actual capital expenditures to OEB-approved capital expenditures were provided in the EGD and Union ESM proceedings. Actual capital expenditures are provided in the Enbridge Gas ESM proceedings.

Table 1
Earning Sharing Mechanism Filings

Line No.	Earnings Sharing Docket	Utility and Reporting Year
1	EB-2015-0122	EGD - 2014
2	EB-2015-0010	Union - 2014
3	EB-2016-0142	EGD - 2015
4	EB-2016-0118	Union - 2015
5	EB-2017-0102	EGD - 2016
6	EB-2017-0091	Union - 2016
7	EB-2018-0131	EGD - 2017
8	EB-2018-0105	Union - 2017
9	EB-2019-0105	EGI - 2018
10	EB-2020-0134	EGI - 2019
11	EB-2021-0149	EGI - 2020
12	EB-2022-0110	EGI - 2021

6. Enbridge Gas received OEB approval to amalgamate in 2018 under the Mergers, Acquisitions, Amalgamations and Divestitures (MAADs) Decision[2] with a 5-year deferred rebasing term from 2019 to 2023. Integration capital expenditures which were required to amalgamate EGD and Union were incurred over the 2019 to 2023 period and included in the annual ESM fillings. Integration capital projects were not eligible in the determination of annual Incremental Capital Module (ICM) amounts

[1] ESM in this context refers to the annual deferral and variance account clearing applications filed by EGD, Union and Enbridge Gas.
[2] EB-2017-0306, EB 2017-0307.

and were not recovered through base rates during the deferred rebasing term. Exhibit 1, Tab 9, Schedule 1 provides information regarding utility consolidation activities including details on integration capital projects.

7. Through careful consideration of capital expenditures, Enbridge Gas has continued to provide safe and reliable service to its customers. The evidence that follows provides further information on capital expenditures over the 2013 to 2018 and 2019 to 2024 time periods.

2. Summary of Capital Expenditures 2013 to 2018 – EGD

8. Table 2 provides a summary of EGD capital expenditures from 2013 to 2018. As provided at Exhibit 2, Tab 5, Schedule 1, EGD operated under a Custom IR[3] framework during the 2014 to 2018 period which included approved capital budgets for 2014 to 2016. The 2016 budget informed the expected spend for the 2017 and 2018 budgets. EGD filed annual ESM applications which described the variances in spend between actual and budgeted capital expenditures.

[3] EB-2012-0459.

4.1. 2020 Actual vs 2019 Actual

24. Table 7 provides a comparison of 2019 and 2020 actual capital expenditures for Enbridge Gas. The 2020 actual expenditure of $1,007.2 million is $80.2 million lower than the 2019 actual of $1,087.4 million. This is primarily driven by a reduction in spend on reinforcement projects as a result of completing the Kingsville Reinforcement Project[18] in 2019.

Table 7
Comparison of Utility Capital Expenditures 2019 Actual & 2020 Actual

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2020 Actual Over/(Under) 2019 Actual
		(a)	(b)	(c) = (b-a)
1	Compression Stations	25.5	26.5	1.0
2	Customer Connections	190.4	178.7	(11.8)
3	Distribution Pipe	175.1	192.8	17.7
4	Distribution Stations	39.7	61.4	21.6
5	Fleet & Equipment	26.3	20.2	(6.1)
6	Growth - Distribution System Reinforcement	144.1	70.0	(74.1)
7	Real Estate & Workplace Services	42.0	38.3	(3.7)
8	Technology Information Services	48.9	22.7	(26.1)
9	Transmission Pipe and Underground Storage	20.3	33.5	13.2
10	Utilization	99.3	62.9	(36.4)
11	Extended Alliance Fixed Overhead	17.8	19.5	1.7
12	Capitalized Overheads	215.2	220.9	5.7
13	Integration Capital	21.7	39.8	18.1
14	Community Expansion	17.1	20.9	3.8
15	Other	3.9	(0.9)	(4.8)
16	Total	1,087.4	1,007.2	(80.2)

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC

[18] EB-2018-0013.

a) Compression Stations: This asset class includes compression facilities used in the natural gas transmission system to move gas throughout the transmission pipelines and to move gas in and out of storage facilities. It also includes dehydration facilities which are used to remove moisture from natural gas to ensure that the gas entering the transmission system meets the contractual standards for moisture content. Spend remained relatively consistent in 2019 and 2020;
b) Customer Connections: This asset class (a subclass of the Growth asset class in Section 5.1.4 of the Asset Management Plan (AMP)), provided at Exhibit 2, Tab 6, Schedule 2, includes the cost of adding new customers to the distribution system. Costs include materials and installation costs of mains and services as well as the meter and regulator installation at the customer site. The decrease of $11.8 million is related to the OEB's Decision on the Company's 2019 Rates Application[19] and a decrease in residential connections as a result of COVID-19. In its decision, the OEB directed Enbridge Gas to refund customers who were impacted by the change in the Customer Connection Policy implemented in 2015, resulting in a one-time increase in spend of $25.5 million in 2019. This was offset partially by a strong greenhouse market in the Union rate zones, the introduction of the Private Sewer Lateral Locate program and aligning the presentation of costs for the Union rate zones by moving the meter and regulator install costs for new customers from Utilization to Customer Connections.
c) Distribution Pipe: This asset class includes pipelines and components used to transport natural gas within the distribution system or to end-use customers. It includes the cost of maintaining, replacing or renewing steel and plastic pipelines as well as services to customers. The increase of $17.7

[19] EB-2018-0305.

million is primarily due to increases in spend related to the Integrity Program, construction costs related to the Windsor Line Replacement Project[20] and development costs related to the London Line Replacement Project[21]. This is partially offset by a decrease to municipal relocations, fewer service relays and completion of the Don River 30” Pipeline Project[22].

d) Distribution Stations: This asset class includes above grade facilities designed to reduce the operating pressure of natural gas pipelines systems in order to distribute gas to lower pressure pipelines that supply natural gas to cities and towns. The increase of $21.6 million is primarily related to the Blackhorse Gate Project, the Cookstown Gate Project, the Hamilton Gate Project, the Oxford Gate Project and Kitchener Gate Project.

e) Fleet & Equipment: This asset class includes the cost of vehicles, trailers, heavy work equipment and tools owned by Enbridge Gas in order to support business needs. The decrease of $6.1 million is related to a change in spend as a result of standardizing the processes and procedures related to the assignment of vehicles for the appropriate roles, types of vehicles required to support employees in performing their roles, and the vehicle maintenance and repair model in the EGD and Union rate zones.

f) Growth: The Growth asset class includes reinforcements driven by customer and load growth. The decrease of $74.1 million was primarily related to the completion of the Kingsville Transmission and Stratford Reinforcement ICM projects in 2019 offset by the Owen Sound Transmission Project in 2020. 2020 spend was also reduced in both rate zones as a result of construction delays due to new provincial social distancing restrictions and work stoppages related to COVID-19.

[20] EB-2019-0172.
[21] EB-2020-0192.
[22] EB-2018-0108.

g) REWS: This asset class includes the cost of properties (buildings and land) and furnishings. There is a base spend for each rate zone that supports building repairs and acquisition of furnishings. Variances are driven by the specific land purchases and building renovations that occur in a given year. Land acquisitions are driven by market availability and are aligned with the long-term strategies described in the AMP, provided at Exhibit 2, Tab 6, Schedule 2. The decrease of $3.7 million is primarily related to the timing of land purchases and building renovations. 2020 spend included property purchases of land adjacent to the Kennedy Road facility in Toronto to support planned expansion of the facility and in London to prepare for the construction of a new London facility. In addition to land purchases, there were construction costs related to the new Belleville facility and renovation costs for the Keil Drive facility. This is offset by a decrease in land spend compared to 2019 related to the purchase of land adjacent to the Toronto Operations Centre (TOC) in Markham to prevent encroachment due to urban sprawl on the site.

h) TIS: This asset class includes the cost of general and specialized hardware, software assets consisting of packaged or developed applications and communication assets. The decrease of $26.1 million is related to the completion of the Contrax Modernization, Customer Information System (CIS) Hardware Replacement and Geographic Information System (GIS) upgrade projects in 2019. Base capital spend was reduced as a result of increased activity on integration projects required to merge EGD and Union systems. All spend related to amalgamating systems as driven by utility consolidation is captured under the Integration category.

i) Transmission Pipe and Underground Storage (TPUS): This asset class includes the pipelines that form the backbone of the gas transmission system as well us the underground storage reservoirs in St. Clair Township near

Sarnia, Crowland Township in Welland, and in Chatham-Kent. The increase of $13.2 million is related to replacements driven by the Class Location program as well as an increase in retrofits and integrity digs driven by the Transmission Integrity Management Program (TIMP).

j) Utilization: This asset class includes measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems. The decrease of $36.4 million was related to the higher meter installations in 2019, a reduction in meter installations related to COVID-19 in 2020 and aligning the presentation of costs for Union by moving the meter and regulator install costs for new customers from Utilization to Customer Connections.

k) Extended Alliance (EA) Fixed Overhead: The EA fixed overhead asset class includes costs for Alliance partner overheads and district contractor pre-work costs. Spend was relatively consistent in 2019 and 2020.

l) Capitalized Overhead: This category includes the allocation of capitalized O&M and IDC. The increase of $5.7 million is related to the implementation of a harmonized overhead capitalization policy in 2020. The harmonized overhead capitalization policy is provided at Exhibit 2, Tab 4, Schedule 2. The policy change resulted in an increase in the amount of capitalization due to the alignment of capitalization rates for Enbridge Gas partially offset by a reduction in total overheads as a result of reduced O&M spend.

m) Integration Capital: This category includes expenditures required to integrate EGD and Union onto common systems, processes and facilities. A summary of all integration activities undertaken during the deferred rebasing term is provided at Exhibit 1, Tab 9, Schedule 1, Table 2. The spend in 2019 was primarily related to the Customer Experience and CIS Upgrade projects. The increase of $18.1 million in 2020 is related to the CIS Project, the Integrated

Utility Asset & Work Management System Phase 1 (AWS) and the Cost of Gas (COG) projects.

n) Community Expansion: This category captures the expenditures required to expand the natural gas distribution system to include customers that did not previously have access to natural gas. The increase of $3.8 million is related to construction of the Scugog Island First Nation Project partially offset by the completion of the Fenelon Falls Project.

o) Other: This category includes expenditures for CNG Rental Stations, RNG Injection Stations and Hydrogen Blending. The decrease of $4.8 million is primarily due to less spend on the CNG Rental Stations Program in 2020.

4.2. 2021 Actual vs 2020 Actual

25. Table 8 provides a comparison of 2021 and 2020 Actuals for Enbridge Gas. The 2021 actual expenditure of $1,310.8 million is $303.6 million higher than the 2020 actual of $1,007.2 million. This is primarily driven by construction of the London Line Replacement Project[23] and Sarnia Industrial Line Reinforcement[24], integrity spend for retrofits and digs and increased spend on integration projects. Effective 2021, Enbridge Gas changed the presentation of overheads as a separate asset class and began showing the allocation of overheads directly to the applicable asset classes. The presentation of overheads is shown as an allocation to projects based on the total direct capital spend by rate zone. This is consistent with the presentation of overheads in the AMP and ICM applications for 2021. The impact related to the shifting of overheads is included in each Asset Class explanation below. The 2021 total overheads are an increase of $14 million compared to 2020 actual due to an increase in overhead capitalization rates, higher gross O&M expenditures relative to 2020 and higher IDC costs due to multi-year projects.

[23] EB-2020-0192.
[24] EB-2019-0218.

Table 7
Utility Capital Expenditures by Asset Class
March Filing Versus Capital Update

Line No.	Particulars ($ millions)	Category	2023 As Filed	Carry Forward From Prior Year (+)	New (+)	Cancelled /Deferred to Subsequent Year (-)	Other (+/-) (3)(4)	2023 Update
			(a)	(b)	(c)	(d)	(e)	(f)=(a+b+c+d+e)
1	Compression Stations	Storage	239.2	20.7	4.2	(18.8)	76.5	321.8
2	Customer Connections	Growth	220.4	0.0	0.0	0.0	65.8	286.3
3	Distribution Pipe	Dist Ops	261.9	36.4	23.6	(83.4)	(1.1)	237.5
4	Distribution Stations	Dist Ops	149.3	10.3	10.0	(58.6)	(43.5)	67.5
5	Fleet & Equipment	General	25.5	0.0	2.3	0.0	(18.9)	8.9
6	Growth - Distribution System Reinforcement	Growth	54.9	1.7	26.1	(14.3)	(13.5)	55.1
7	Real Estate & Workplace Services	General	52.1	0.5	2.5	(16.8)	24.7	63.0
8	Technology Information Services	General	63.7	1.3	2.4	(12.4)	(7.9)	47.1
9	Transmission Pipe and Underground Storage	Storage	280.7	39.9	4.4	(255.1)	9.1	79.0
10	Utilization	Dist Ops	136.5	0.0	0.0	0.0	24.2	160.7
11	Extended Alliance Fixed Overhead	Other	21.7	0.0	0.0	0.0	3.9	25.6
12	Integration Capital	Other	43.6	5.1	1.2	(29.9)	0.0	20.0
13	Community Expansion	Growth	14.0	0.0	0.0	0.0	6.6	20.6
14	Other	Other	42.0	0.0	0.0	(7.7)	0.0	34.3
15	Total		1,605.7	115.9	76.7	(497.0)	125.9	1,427.2

Notes:
(1) Expenditures are shown by asset class inclusive of IDC and overheads and net of contributions.
(2) Expenditures are shown on an annual basis.
(3) Includes changes in capex estimates, allocation of Overheads, profiling differences, etc.
(4) Panhandle Regional Expansion Project capex reductions of $22.7M in 2023.

a) Compression Stations: The increase of $82.5 million in compression stations is attributed to $16.4 million of delayed expenditures from 2022 for D2C compounded by a cost increase of $69.3 million for planned work 2023 for this project. This variance is further compounded by small carry over costs, increases to planned projects and costs associated with unplanned failures which are partially offset by $18.8 million in deferrals and decreases for several other smaller projects.
b) Customer Connections: The increase in $65.9 million is related to an overall increase in forecasted new customer connections compounded with inflationary pressures in construction and material costs.
c) Distribution Pipe: While there is an overall decrease of $24.5 million, cost pressures have been identified. These cost pressures include $30.8 million of 2022 carry over costs for KOL Cherry to Bathurst, $5.6 million in carry over costs for several smaller distribution pipe projects, $8.9 million worth of new pipeline replacement and class location projects, and $14.2 million in new integrity digs and exposed water way crossing replacements. These cost pressures have been offset through reprioritization of $84 million in integrity retrofits and depth of cover work, reductions to pipeline relocation blankets based on updated municipal construction plans, and reprioritization of main replacement and corrosion expenditures.
d) Distribution Stations: The decrease of $81.9 million is primarily related to $19.1 million for the delay of the Lisgar Gate station as the project is rescoped, $23.6 million for deferral of the Crowland station, and deferrals and reductions of $59.5 million in other smaller station projects during portfolio reprioritization which are partially offset by increases of $10.3 million in carry over costs from 2022 and $10 million in new station investments identified through inspections and equipment failures.

e) Fleet & Equipment: The decrease of $16.7 million is related to identification of $2.3 million in requirements for new tools and equipment offset by savings of $18.9 million from reprioritization for vehicles and equipment purchases.
f) Growth: While there have been $26.1 million in new growth projects identified in 2023, these have been offset by equivalent savings from things such as deferral and downsizing of planned growth projects following review of specific customer connection projects and resultant system constraints. As a result, there is a small variance.
g) Real Estate and Workplace Services: The increase of $10.9 million is primarily related to a $22.1 million increase for the SMOC/Coventry (Ottawa Building) Facility project driven by a change to timing for the project. This increase has been partially offset by a $12 million reduction to the new Station B building through adjusted pacing of construction and other minor reductions to the forecast.
h) Technology Information Services: The decrease of $16.6 million is related to reprioritization of the TIS Business Solutions portfolio based on business needs resulting in $20.3 million in reductions and deferrals partially offset by $3.5 million in carry over costs and new investments.
i) Transmission Pipe and Underground Storage: The decrease of $201.8 million is related to deferral of $223.5 million for PREP, deferral of $8.9 million for the Crowland Wells Upgrade project, and several other small projects that were reduced or saw changes to forecast during updated forecasting and reprioritization of the portfolio amounting to an additional $13.9 million reduction. These reductions were offset by $38.9 million in 2022 materials costs for the Panhandle Regional Expansion projects and $4.5 million from other smaller projects being carried into 2023, and minor increases to the Integrity Management Program resulting primarily from work

carrying over from prior years and an increase to planned digs compounded with inflationary pressures.

j) Utilization: The increase of $24.2 million is primarily a result of $5.5 million costs for delayed meters ordered for 2022, an increase of $15.1 million for meters ordered for receipt in 2023 to build inventory for increased customer connections and meter exchange activity, a $2.3 million increase in regulators and meter exchange labour costs, associated with a moderate increase in planned work to catch up on work not complete in 2022, and some other minor increases in the portfolio.

k) EA Fixed Overhead: The increase of $3.9 million is related to the inclusion of third party pre-work blankets in the EA Fixed Overhead asset class.

l) Integration Capital: The decrease of $23.7 million is due to the deferral of the GTA East and GTA West REWS projects totalling $29.9 million offset by carry forward spend from 2022 for TIS integration projects totalling $6.3 million.

m) Community Expansion: The increase of $6.6 million is due to shifts in timing for the execution of NGEP Phase 2 projects.

n) Other: The decrease of $7.8 million is due to the deferral of customer driven RNG projects to 2024.

2024 Test Year (Capital Update) vs 2024 Test Year (March Filing)

24. The 2024 Test Year (Capital Update) expenditure of $1,470.3 million is $21.1 million lower than the 2024 Bridge Year (March Filing) of $1,491.3 million. There are several factors driving the variances including a reprioritization of the portfolio to support increases to the integrity and customer connections portfolios and inflationary pressures on projects overall. Note that the capital expenditures related

2.4. Integration Capital Expenditures and Inclusion in Rate Base

42. To deliver the benefits of integration, pillar system alignment was required to effectively manage business operations and customer interactions for over 3.8 million customers. Supporting multiple billing and work management systems with disparate processes and structures was not an effective way to deliver reliable, scalable, efficient service to customers, nor an effective way to maintain ongoing business operations. Investments throughout the deferred rebasing term brought the utility to common, modern, scalable platforms. These platforms provide foundations that deliver sustainable savings and ongoing benefits in common user experiences and practices across Enbridge Gas that will extend beyond the deferred rebasing term. Over the deferred rebasing term, Enbridge Gas expects to incur approximately $252.2 million in capital expenditures related to integration efforts (Table 6). The revenue requirement to support these investments was not included in base rates, and as such was borne by the shareholder. The largest capital expenditures were in pillar technologies: one Customer Information System (CIS), one Asset and Work Management (AWS) system and buildings to effectively align areas with geographic proximity supporting field operations.

43. By December 31, 2023, the residual net book value of the integration capital projects is forecasted to be $178.5 million. The associated impact reflected in the 2024 Test Year revenue requirement is $34 million, further details at paragraph 49. A listing of the integration capital expenditures and descriptions is provided at Attachment 1. The CIS investments are included in Customer Care, the AWS investments are noted in Distribution Operations, and the real estate and building investments are reflected in Other Functions.

Table 6
Integration CapEx Investments Schedule

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	CapEx						
1	Business Development & Regulatory		0.6	2.0			
2	Customer Care	6.7	27.7	32.0			
3	Distribution Operations	11.3	7.1	19.0	27.0	13.7	
4	Energy Services	3.6	3.7	8.0	3.0		
5	Engineering & STO		0.2	2.0	1.0		
6	Other Functions			24.5	10.6	29.9	
7	Overheads	7.6	11.0				
8	Total Annual CapEx	29.1	50.4	87.5	41.6	43.6	252.2
9	Net Book Value (included in rate base forecast)						178.5

Notes:
(1) Real Estate CapEx in "Other Functions" to align facilities GTA East and GTA West
(2) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment
(3) CapEx is reflective of year spent
(4) Overheads are included at the project level starting in 2021
(5) Associated impact of NBV reflected in the 2024 Test Year revenue requirement is $34 million

44. As noted, the largest investments in capital were driven by technology investments to align pillar applications, which started in 2019. Upon initiation, these projects assessed the current systems in place against business needs, the evolving technology landscape and security requirements, as well as evolving customer expectations to determine the solutions to deliver on those requirements safely and reliably for Enbridge Gas. The decision to upgrade and migrate to existing systems provided significant benefits to customers, as implementing new systems would have been more expensive solutions.

45. As referenced in the savings section of this evidence, the CIS in Customer Care was a significant integration project for Enbridge Gas. The CIS in use prior to amalgamation were nearing end of life and migrating the UG Banner/ Enlogix CIS to the SAP S/4 HANA cloud application, mitigated sustainability issues and improved the reliability of the systems. The aligned CIS and complex interfaces to inter-related systems also enabled one common CIS platform and delivered a common brand and customer experience across Enbridge Gas. This foundational investment in the aligned billing system delivered synergy savings and served to modernize the system on which operational processes and customers continue to rely.

46. Another significant technology platform was delivered through the Asset and Work Management system implemented in Distribution Operations. The Asset and Work Management system enabled the efficient workload planning and execution in operations and set the stage for a scalable solution implemented through phases. This project initially migrated the service suite planning and dispatch application, along with related systems and processes in use at Union Gas pre-amalgamation into the Maximo system, creating alignment for utility maintenance work. This initiative expanded to a phased implementation leveraging system and processes for construction, meter shop, and planning for station operations. This integrated asset and work management system (Maximo) brought both companies onto a common platform with aligned policies, processes, and procedures for Distribution Operations, Customer Care, and Engineering while supporting Enbridge Gas's goals in achieving safe, efficient, and reliable operations. These implementations included planning, execution, and reporting activities, as well as the implementation of a mobility solution for the field workforce. This aligned system is fundamental to work and asset management across the utility, enabling safe, reliable, and effective

service to customers through work order management, asset reliability and emergency response.

47. In Energy Services, an investment in technology and an aligned, automated Cost of Gas Application delivered an integrated solution to purchase and contract, nominate, manage invoicing, manage credit requirements, and book gas costs and associated deferrals for financial and regulatory reporting, as well as inventory management across Enbridge Gas.

48. Additional capital expenditures for real estate needs resulting from integration are identified in Other Functions. Enbridge Gas completed a strategic review of the real estate locations and buildings used for office and operational needs, including a review of regional operating boundaries for field operations. Specific to the amalgamated utility, opportunities for reduction were identified considering geographic location and proximity. This resulted in decisions for a new Greater Toronto Area (GTA) East location to service the combined Peterborough and Cobourg areas, and a new GTA West location consolidating Burlington, Milton, and Brampton service areas. The new facilities are forecasted to be substantially complete by December of 2023 with occupation taking place in the first half of 2024. Enbridge Gas expects to dispose of the Peterborough, Cobourg, Burlington, Milton, and Brampton locations in 2024, and has forecasted these dispositions in 2024 rate base. Enbridge Gas has not forecasted gains or losses related to the dispositions due to the volatility of market conditions, and actual results will be disclosed in the annual earning sharing applications. Once in-service, the new facilities are expected to generate annual operational savings of approximately $0.2 million for the GTA West location and approximately $0.1 million for the GTA East location. Due to timing of movements and dispositions, these savings are expected to begin in 2025.

49. Enbridge Gas's expectation is that the net book value capital costs of the integration will be included in rate base in 2024 and be subject to recovery through rates going forward. These investments were made throughout the deferred rebasing term to deliver the highest level of sustainable savings and operational benefits. Much of the residual net book value of the PPE pertains to in-service additions in 2021, 2022, and 2023, which Enbridge Gas will not have had the opportunity to fully depreciate by the end of the approved 5-year deferred rebasing term.

50. Beginning in 2024, Enbridge Gas will reflect the impact of the efficiencies and cost savings resulting from the amalgamation in its going-forward rates. At the same time, it is appropriate that remaining costs from capital projects aimed at integration and delivering benefits should also be reflected in Enbridge Gas's rates. The expected annual synergy savings of $86 million resulting from all integration initiatives, net of $34 million in annual depreciation, based on proposed depreciation rates pursuant to the depreciation study provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1, taxes and carrying charges related to these projects will be passed on to customers during the next IR term and beyond, flowing through as a net reduction of $52 million to the revenue requirement in 2024.

51. This approach reflects the principle that benefits follow costs and is consistent with the fact that, under US GAAP, the costs of the amalgamation/ integration investments are expensed, as depreciation, over the period when they are providing value. These investments in complex systems have extended depreciation terms due to the life of the asset. These systems provide the foundation upon which business processes and customer experiences are built to

deliver safe and reliable services to current and future customers. Considering that this value is credited to customers through rebasing, so too should the costs be charged to customers at that time. The capital investments made will continue to provide value and service to customers and establishing their continued rate base treatment and draw down through depreciation is consistent with how other utility assets are treated, and consistent with how GAAP requires assets to be treated. This treatment aligns the ongoing benefits for customers with the associated costs in rates.

3. Summary

52. At the end of 2023, with the end of the deferred rebasing term, Enbridge Gas will have completed the approved MAADs framework. Consistent with the commitments in the MAADs framework, the O&M costs incurred for integration activities are not included in proposed rates for 2024. The annual integration synergies of $86 million demonstrate the amalgamation of EGD and Union provides ongoing benefits to customers. As those savings are passed on to customers in 2024, it is appropriate the corresponding net book value of integration costs of the assets used to provide continued safe and reliable services are included in rate base. This evidence compiled the view of the integration activities that were completed through the deferred rebasing term, which generated a net reduction of $52 million to the 2024 Test Year revenue requirement.

2.4. Integration Capital Expenditures and Inclusion in Rate Base

42. To deliver the benefits of integration, pillar system alignment was required to effectively manage business operations and customer interactions for over 3.8 million customers. Supporting multiple billing and work management systems with disparate processes and structures was not an effective way to deliver reliable, scalable, efficient service to customers, nor an effective way to maintain ongoing business operations. Investments throughout the deferred rebasing term brought the utility to common, modern, scalable platforms. These platforms provide foundations that deliver sustainable savings and ongoing benefits in common user experiences and practices across Enbridge Gas that will extend beyond the deferred rebasing term. Enbridge Gas expects to incur $189.0 million in capital /u
expenditures related to integration efforts over the deferred rebasing term as set out in Table 6. This represents a reduction of approximately $63.2 million relative to /u
Enbridge Gas's original forecast. The primary driver for the change in capital /u
expenditures is the deferral of the GTA East and GTA West facility integration /u
projects. Enbridge Gas is re-evaluating the costs and timing of the GTA East and /u
West projects due to delays to the construction schedules and a forecasted /u
increase in the construction costs for the facilities. /u

43. The revenue requirement to support these investments was not included in base rates, and as such was borne by the shareholder. The largest capital expenditures were in pillar technologies: one Customer Information System (CIS) and one Asset and Work Management (AWS) system. /u

44. By December 31, 2023, the residual net book value of the integration capital projects is forecasted to be $119 million. The associated impact reflected in the /u
2024 Test Year revenue requirement is $28 million, further details at paragraph 49. /u

A listing of the integration capital expenditures and descriptions is provided at Attachment 1. The CIS investments are included in Customer Care and the AWS investments are noted in Distribution Operations. /u

Table 6
Integration CapEx Investments Schedule

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	
	CapEx							
1	Business Development & Regulatory		0.6	2.0			2.6	
2	Customer Care	6.7	27.7	32.0	0.8		67.3	/u
3	Distribution Operations	11.3	7.1	19.0	19.8	17.0	74.2	/u
4	Energy Services	3.6	3.7	8.0	5.6	3.0	23.9	/u
5	Engineering & STO		0.2	2.0	0.3		2.5	/u
6	Overheads	7.6	11.0				18.6	
7	Total Annual CapEx	29.1	50.4	63.0	26.5	20.0	189.0	/u
8	Net Book Value (included in rate base forecast)						119.0	/u

Notes:
(1) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment /u
(2) CapEx is reflective of year spent /u
(3) Overheads are included at the project level starting in 2021 /u
(4) Associated impact of NBV reflected in the 2024 Test Year revenue requirement is $28 million /u

45. As noted, the largest investments in capital were driven by technology investments to align pillar applications, which started in 2019. Upon initiation, these projects assessed the current systems in place against business needs, the evolving technology landscape and security requirements, as well as evolving customer

expectations to determine the solutions to deliver on those requirements safely and reliably for Enbridge Gas. The decision to upgrade and migrate to existing systems provided significant benefits to customers, as implementing new systems would have been more expensive solutions.

46. As referenced in the savings section of this evidence, the CIS in Customer Care was a significant integration project for Enbridge Gas. The CIS in use prior to amalgamation were nearing end of life and migrating the UG Banner/ Enlogix CIS to the SAP S/4 HANA cloud application, mitigated sustainability issues and improved the reliability of the systems. The aligned CIS and complex interfaces to inter-related systems also enabled one common CIS platform and delivered a common brand and customer experience across Enbridge Gas. This foundational investment in the aligned billing system delivered synergy savings and served to modernize the system on which operational processes and customers continue to rely.

47. Another significant technology platform was delivered through the Asset and Work Management system implemented in Distribution Operations. The Asset and Work Management system enabled the efficient workload planning and execution in operations and set the stage for a scalable solution implemented through phases. This project initially migrated the service suite planning and dispatch application, along with related systems and processes in use at Union Gas pre-amalgamation into the Maximo system, creating alignment for utility maintenance work. This initiative expanded to a phased implementation leveraging system and processes for construction, meter shop, and planning for station operations. This integrated asset and work management system (Maximo) brought both companies onto a common platform with aligned policies, processes, and procedures for Distribution Operations, Customer Care, and Engineering while supporting Enbridge Gas's

goals in achieving safe, efficient, and reliable operations. These implementations included planning, execution, and reporting activities, as well as the implementation of a mobility solution for the field workforce. This aligned system is fundamental to work and asset management across the utility, enabling safe, reliable, and effective service to customers through work order management, asset reliability and emergency response.

48. In Energy Services, an investment in technology and an aligned, automated Cost of Gas Application delivered an integrated solution to purchase and contract, nominate, manage invoicing, manage credit requirements, and book gas costs and associated deferrals for financial and regulatory reporting, as well as inventory management across Enbridge Gas.

49. Enbridge Gas's expectation is that the net book value capital costs of the integration will be included in rate base in 2024 and be subject to recovery through rates going forward. These investments were made throughout the deferred rebasing term to deliver the highest level of sustainable savings and operational benefits. Much of the residual net book value of the PPE pertains to in-service additions in 2021, 2022, and 2023, which Enbridge Gas will not have had the opportunity to fully depreciate by the end of the approved 5-year deferred rebasing term.

50. Beginning in 2024, Enbridge Gas will reflect the impact of the efficiencies and cost savings resulting from the amalgamation in its going-forward rates. At the same time, it is appropriate that remaining costs from capital projects aimed at integration and delivering benefits should also be reflected in Enbridge Gas's rates. The expected annual synergy savings of $86 million resulting from all integration initiatives, net of $28 million in annual depreciation, based on proposed /u

depreciation rates pursuant to the depreciation study provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1, taxes and carrying charges related to these projects will be passed on to customers during the next IR term and beyond, flowing through as a net reduction of $58 million to the revenue requirement in 2024. /u

51. This approach reflects the principle that benefits follow costs and is consistent with the fact that, under US GAAP, the costs of the amalgamation/ integration investments are expensed, as depreciation, over the period when they are providing value. These investments in complex systems have extended depreciation terms due to the life of the asset. These systems provide the foundation upon which business processes and customer experiences are built to deliver safe and reliable services to current and future customers. Considering that this value is credited to customers through rebasing, so too should the costs be charged to customers at that time. The capital investments made will continue to provide value and service to customers and establishing their continued rate base treatment and draw down through depreciation is consistent with how other utility assets are treated, and consistent with how GAAP requires assets to be treated. This treatment aligns the ongoing benefits for customers with the associated costs in rates.

3. Summary

52. At the end of 2023, with the end of the deferred rebasing term, Enbridge Gas will have completed the approved MAADs framework. Consistent with the commitments in the MAADs framework, the O&M costs incurred for integration activities are not included in proposed rates for 2024. The annual integration synergies of $86 million demonstrate the amalgamation of EGD and Union provides ongoing benefits to customers. As those savings are passed on to customers in 2024, it is appropriate

Capital Expenditures Integration Projects - Detailed Listing

Line No.	Particulars ($000s)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description
1	Shared Services	REWS-GTA West Building	Dec 2023	57.5	0.0	57.5	This project consolidates facilities in the West/Niagara region and retires of two existing facilities. This is required due to Enbridge Gas operations boundary realignment to enable the operational teams to operate efficiently and results in facility savings.
2	Customer Care	CIS Integration	July 2021	44.7	11.8	37.1	Integration to a common Customer Information Systems (CIS) resulting in the retirement of the UG Banner CIS, and required upgrade and migration to one SAP platform to ensure ongoing reliable operations.
3	Operations	Asset & Work Management Systems (AWS)	July 2021 July 2022 July 2023	46.6	17.4	31.7	This project delivers the integrated Utility Asset & Work Management Systems (AWS) harmonizing work management systems for maintenance operations, construction, and customer attachment, and integrating to the Maximo system previously used by EGD. This project is executed in Phases: Phase 1: integration of work management systems to a common Maximo platform; Phase 2: integration of Construction, Attachment, and Meter Shop systems and processes for Maximo, GetConnected, and Customer Connections Work Suite; Phase 3: Align Station Operations for both EGD and Union to Maximo.
4	Customer Care	CIS Integration - HANA	July 2020	16.1	7.5	11.8	This implementation is part of the CIS Integration Project, moving the UG Banner CIS information to the S4 HANA cloud application
5	Shared Services	REWS - GTA East Building	Dec 2023	9.8	0.0	9.8	This project consolidates facilities in the Eastern region and will retire two existing facilities. This is required due to Enbridge Gas operations boundary realignment to enable the operational teams to operate efficiently and results in facility savings.
6	Energy Services	Cost of Gas Replacement	Feb 2022	14.8	7.5	8.8	A single integrated Utility Gas Purchase and Financial Reporting automated solution is required to manage risks and ensure successful integration in Energy Services and Finance. The driver was to align processes and systems across Enbridge Gas to purchase and contract, nominate, manage credit requirements and track gas costs for financial reporting, inventory management, and deferrals for multiple rate zones.

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($000s)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description
7	Operations	Leak and Corrosion System Integration	Nov 2022	5.2	1.5	3.7	This project implements a unified solution to enable Leak and Corrosion Survey process integration between EGD and Union. The project delivers the technology solution that will support the integrated Corrosion and Leak survey processes by replacing the existing platforms (CSMS, LSMS, DNV-GL) and moving EGD and Union onto the same technology solution.
8	Operations	Estimating & Forecasting Accuracy	Nov 2022	2.9	0.8	2.1	This project implements a harmonized capital project estimating tool (EcoSys) to provide consistent and reliable capital estimation, benchmarking, and resource planning through integrated processes and system. Future opportunities include adding capital forecasting and additional reporting functionality for GDS.
9	Operations	Tools Lifecycle mngmt Soln Integration	Nov 2023	2.0	0.0	2.0	This project harmonizes the tool and equipment programs and processes across Distribution Operations with a focus on a small tool purchase process, new tool requests and approvals, selection of special tools, and a new tool inspection process improving employee safety and to increase operational reliability and efficiencies.
10	Operations	ePackaging	Nov 2023	1.9	0.0	1.8	This project digitizes work packages and provide a single solution and process for accessing locates and permits information and other reference information (e.g. Site/Hazard assessment forms) to support efficient work management.
11	Engineering	Meter Shop Consolidation	Dec 2021	1.9	0.1	1.8	This project consolidates the three existing Meter Shops (Chatham, North Bay and VPC) into two. Results in closure of the Meter Shop at VPC.
12	Customer Care	IVR Enhancements and Consolidation	July 2021	2.9	2.0	1.3	This project is to enhance and consolidate the EGD and Union Interactive Voice Response (IVR) into a single Enbridge Gas IVR with the focus to increase the containment within the IVR and ultimately integrate call handling between the internal and external contact centers for Phase 2 go live of CIS - SAP S/4 HANA on cloud. Enables Enbridge Gas to deliver on a single consistent experience to customers and present Enbridge Gas as a single company.

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($000s)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description
13	Business Development	Website Integration	July 2021	2.8	1.8	1.2	This project integrates uniongas.com and enbridgegas.com to support the amalgamated utility. New website will use enbridgegas.com and implement enhancements to reflect combined utility business unit needs. This implementation includes content, functionality, infrastructure and processes.
14	Operations	Emergency Solutions Harmonization	Nov 2022	1.6	0.5	1.2	The project delivers the technology solutions to support Enbridge Gas's integrated Emergency Response processes and amalgamation of dispatch centers by bringing both EGD and Union onto the same Interactive Voice Response and paging solutions.
15	Operations	Locate Tracker Rollout to Union	Nov 2023	1.4	0.1	1.2	that EGD and Union will use to align their processes and procedures for ordering and tracking locates for internal dig work, supporting work management and damage prevention efforts.
16	Customer Care	My Account Amalgamation	July 2021	2.2	1.5	1.0	This project will provide customers across Enbridge Gas with one My Account experience. This will be done in parallel with the CIS Integration project as UG customers migrate over to the Enbridge Gas My Account, maintaining a consistent and positive user experience.
17	Operations	Harmonize feasibility Tools	Nov 2023	1.0	0.0	1.0	This project supports the harmonized customer attachment process, and harmonizes the feasibility tool for EGD and Union. This will also provide automatic system archive capabilities for the feasibility analysis instead of needing to post on second SharePoint site. Results in the decommissioning of the Union and EGD models.
18	Energy Services	PowerSpring LVB Integration	Nov 2022	1.2	0.3	0.9	The project supports the integration of business processes and applications to gather measurement data from field devices and ensures measurement integrity while facilitating large volume billing (LVB) accuracy.
19	Operations	Dispatch Scheduling Harmonization	Nov 2022	1.0	0.3	0.7	This project integrates, harmonizes, and automates dispatch scheduling for both EGD and Union supporting work management.
20	Operations	Locate Management Solution Harmonization	Nov 2023	0.7	0.0	0.7	This project is being executed to deliver the technology solution that will bring EGD and Union onto the same platform to support the integrated locate management processes. This solution will provide one source for all locate requests from Ontario One Call supporting damage prevention efforts at EGI.

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($000s)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description
21	Energy Services	Utility Weather & Demand Harmonization	Nov 2022	0.6	0.1	0.4	This project implements a reporting/statistical analysis solution for EGD data in support of the Utility Weather & Demand Harmonization Program. This new solution will mimic a current solution (Load vs Cold) in place for Union data.
22	Operations	EGI Operations-Harmonized Field User Connectivity	Nov 2023	0.4	0.0	0.4	This project aligns the technology platform and technical support for remote connectivity for Enbridge Gas distribution operations field employees.
23	Operations	Customer Connections	April 2020	0.5	0.3	0.3	This project supported the customer connections business processes with a unified solution and retirement of the duplicate systems while also delivering enhanced customer experience.
24	Customer Care	Unionline Rebranding Project	May 2021	0.2	0.2	0.1	This project renames the existing Unionline application, including removing reference of Unionline and Union Gas from existing customer facing transactional system. This also includes contracts, invoices and reports accessed by customers through this platform.
25	Operations	Alignment of Execution of Warning Tags	Nov 2022	0.2	0.1	0.1	This project implements an electronic warning tag solution integrating and automating processes to improve accuracy and efficiencies for the management of appliance warning tags..
26	Operations	Customer Experience	Dec 2019	11.2	16.3	0.0	This project involved a full re-build of the MyEnbridge account management infrastructure, with the costs predominantly comprised of TIS hardware and software.
27	Energy Services	SCADA and Gas Control Consolidation	Nov 2019	3.0	3.6	0.0	This project was to consolidate the utility control center operations in Chatham with migration to a single CygNet SCADA system.
28	Business Development	Bill Print & Presentment	May 2020	0.1	0.0	0.0	This project moves the Union bill print processing and composition to Kubra resulting in a single bill image for Enbridge Gas customers.
29	Overheads			17.9			
30	Total			252.3	73.8	178.5	

Note:
(1) Overheads shown at the project level effective 2021

Capital Expenditures Integration Projects - Detailed Listing

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31	2023 Acc. Dep as at Dec 31	2023 NBV as at Dec 31	Project Description	
				(a)	(b)	(c)		
1	Customer Care	CIS Integration	July 2021	44.7	11.8	37.0	Integration to a common Customer Information Systems (CIS) resulting in the retirement of the UG Banner CIS, and required upgrade and migration to one SAP platform to ensure ongoing reliable operations.	
2	Operations	Asset & Work Management Systems (AWS)	July 2021 July 2022 Dec 2023	48.5	14.4	38.1	This project delivers the integrated Utility Asset & Work Management Systems (AWS) harmonizing work management systems for maintenance operations, construction, and customer attachment, and integrating to the Maximo system previously used by EGD. This project is executed in Phases: Phase 1: integration of work management systems to a common Maximo platform; Phase 2: integration of Construction, Attachment, and Meter Shop systems and processes for Maximo, GetConnected, and Customer Connections Work Suite; Phase 3: Align Station Operations for both EGD and Union to Maximo.	/u
3	Customer Care	CIS Integration - HANA	July 2020	15.5	6.1	11.7	This implementation is part of the CIS Integration Project, moving the EGD CIS information to the S4 HANA cloud application.	/u
4	Energy Services	RACOG	Nov 2023	2.3	0.0	2.3	Revenue and Gas Cost Financial Reporting Project (RACOG). Enable an integrated long-term solution for actual, budget, forecast and key regulatory reporting using consistent tools.	/u
5	Energy Services	Cost of Gas Replacement	Feb 2022	15.8	8.3	9.4	A single integrated Utility Gas Purchase and Financial Reporting automated solution is required to manage risks and ensure successful integration in Energy Services and Finance. The driver was to align processes and systems across Enbridge Gas to purchase and contract, nominate, manage credit requirements and track gas costs for financial reporting, inventory management, and deferrals for multiple rate zones.	/u

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31	2023 Acc. Dep as at Dec 31	2023 NBV as at Dec 31	Project Description	
				(a)	(b)	(c)		
6	Operations	Leak and Corrosion System Integration	Nov 2022	5.7	1.4	4.3	This project implements a unified solution to enable Leak and Corrosion Survey process integration between EGD and Union. The project delivers the technology solution that will support the integrated Corrosion and Leak survey processes by replacing the existing platforms (CSMS, LSMS, DNV-GL) and moving EGD and Union onto the same technology solution.	/u
7	Operations	Estimating & Forecasting Accuracy	Nov 2022	2.9	0.9	2.1	This project implements a harmonized capital project estimating tool (EcoSys) to provide consistent and reliable capital estimation, benchmarking, and resource planning through integrated processes and system. Future opportunities include adding capital forecasting and additional reporting functionality for GDS.	
8	Operations	ePackaging	Nov 2023	1.1	0.0	1.1	This project digitizes work packages and provide a single solution and process for accessing locates and permits information and other reference information (e.g. Site/Hazard assessment forms) to support efficient work management.	/u
9	Operations	Customer Attachment IVR	Nov 2022	0.8	0.3	0.5	This project is to harmonize IVR systems for both EGD and Union. This would include IVR for external customers/Builders/Heating contractors for customer attachment business function.	/u
10	Engineering	Meter Shop Consolidation	Dec 2021	1.9	0.1	1.8	This project consolidates the three existing Meter Shops (Chatham, North Bay and VPC) into two. Results in closure of the Meter Shop at VPC.	
11	Customer Care	IVR Enhancements and Consolidation	July 2021	2.9	2.0	1.3	This project is to enhance and consolidate the EGD and Union Interactive Voice Response (IVR) into a single Enbridge Gas IVR with the focus to increase the containment within the IVR and ultimately integrate call handling between the internal and external contact centers for Phase 2 go live of CIS - SAP S/4 HANA on cloud. Enables Enbridge Gas to deliver on a single consistent experience to customers and present Enbridge Gas as a single company.	

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31 (a)	2023 Acc. Dep as at Dec 31 (b)	2023 NBV as at Dec 31 (c)	Project Description	
12	Business Development	Website Integration	July 2021	2.8	1.8	1.2	This project integrates uniongas.com and enbridgegas.com to support the amalgamated utility. New website will use enbridgegas.com and implement enhancements to reflect combined utility business unit needs. This implementation includes content, functionality, infrastructure and processes.	
13	Operations	Emergency Solutions Harmonization	Nov 2022	2.1	0.6	1.5	The project delivers the technology solutions to support Enbridge Gas's integrated Emergency Response processes and amalgamation of dispatch centers by bringing both EGD and Union onto the same Interactive Voice Response and paging solutions.	/u
14	Operations	Locate Tracker Rollout to Union	Nov 2023	0.9	0.0	0.9	This project involves the roll-out a single application for the Locates Tracker functionality that EGD and Union will use to align their processes and procedures for ordering and tracking locates for internal dig work, supporting work management and damage prevention efforts.	/u
15	Customer Care	My Account Amalgamation	July 2021	2.2	1.5	1.0	This project will provide customers across Enbridge Gas with one My Account experience. This will be done in parallel with the CIS Integration project as UG customers migrate over to the Enbridge Gas My Account, maintaining a consistent and positive user experience.	
16	Operations	Harmonize Feasibility Tools	Nov 2023	1.0	0.0	1.0	This project supports the harmonized customer attachment process, and harmonizes the feasibility tool for EGD and Union. This will also provide automatic system archive capabilities for the feasibility analysis instead of needing to post on second SharePoint site. Results in the decommissioning of the Union and EGD models.	
17	Energy Services	PowerSpring LVB Integration	Jul 2023	2.0	0.2	1.8	The project supports the integration of business processes and applications to gather measurement data from field devices and ensures measurement integrity while facilitating large volume billing (LVB) accuracy.	/u
18	Operations	Dispatch Scheduling Harmonization	Nov 2022	0.4	0.1	0.3	This project integrates, harmonizes, and automates dispatch scheduling for both EGD and Union supporting work management.	/u
19	Operations	Locate Management Solution Harmonization	Nov 2023	0.7	0.0	0.7	This project is being executed to deliver the technology solution that will bring EGD and Union onto the same platform to support the integrated locate management processes. This solution will provide one source for all locate requests from Ontario One Call supporting damage prevention efforts at EGI.	

Capital Expenditures Integration Projects - Detailed Listing (Continued)

Line No.	Particulars ($millions)	Project	In Service Date	2023 Total spend as at Dec 31	2023 Acc. Dep as at Dec 31	2023 NBV as at Dec 31	Project Description	
				(a)	(b)	(c)		
20	Energy Services	Utility Weather & Demand Harmonization	Nov 2022	0.4	0.1	0.3	This project implements a reporting/statistical analysis solution for EGD data in support of the Utility Weather & Demand Harmonization Program. This new solution will mimic a current solution (Load vs Cold) in place for Union data.	/u
21	Operations	EGI Operations-Harmonized Field User Connectivity	Nov 2023	0.2	0.0	0.2	This project aligns the technology platform and technical support for remote connectivity for Enbridge Gas distribution operations field employees.	/u
22	Operations	Customer Connections	April 2020	0.5	0.3	0.2	This project supported the customer connections business processes with a unified solution and retirement of the duplicate systems while also delivering enhanced customer experience.	/u
23	Customer Care	Unionline Rebranding Project	May 2021	0.2	0.2	0.1	This project renames the existing Unionline application, including removing reference of Unionline and Union Gas from existing customer facing transactional system. This also includes contracts, invoices and reports accessed by customers through this platform.	
24	Operations	Alignment of Execution of Warning Tags	Nov 2022	0.2	0.0	0.2	This project implements an electronic warning tag solution integrating and automating processes to improve accuracy and efficiencies for the management of appliance warning tags..	/u
25	Operations	Customer Experience	Dec 2019	11.2	16.3	0.0	This project involved a full re-build of the MyEnbridge account management infrastructure, with the costs predominantly comprised of TIS hardware and software.	
26	Energy Services	SCADA and Gas Control Consolidation	Nov 2019	3.0	3.6	0.0	This project was to consolidate the utility control center operations in Chatham with migration to a single CygNet SCADA system.	
27	Business Development	Bill Print & Presentment	May 2020	0.1	0.0	0.0	This project moves the Union bill print processing and composition to Kubra resulting in a single bill image for Enbridge Gas customers.	
28	Overheads			18.6				/u
29	Total			189.0	70.0	119.0		/u

Note:
(1) Overheads shown at the project level effective 2021

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0306 AND EB-2017-0307

UNION GAS LIMITED
AND
ENBRIDGE GAS DISTRIBUTION INC.

Enbridge Gas Distribution Inc. and Union Gas Limited Application for Amalgamation and Rate-Setting Mechanism

BEFORE: **Lynne Anderson**
Presiding Member

Christine Long
Vice-Chair and Member

Cathy Spoel
Member

August 30, 2018

Amended on September 17, 2018

5.2 Deferred Rebasing Period

The applicants proposed a deferred rebasing period of ten years. In support of their request, the applicants referred to the MAADs Handbook which allows consolidating distributors to select a maximum deferral period of ten years with no supporting evidence to justify the selected deferral period. The applicants maintain that a ten-year deferred rebasing period is necessary to undertake a large and complex integration and to deliver significant integration savings and synergies to ratepayers on rebasing.

With the exception of the Municipality of Chatham-Kent, none of the other parties supported a ten-year deferred rebasing period. The Municipality of Chatham-Kent noted that the rebasing period was necessary to allow the area of Chatham-Kent to adjust to any loss of employment as a result of the amalgamation.

A number of intervenors and OEB staff raised issues related to a long deferral period. These included that:

- A full examination of the two utilities' costs was last undertaken in 2012 and 2013. Decoupling revenues from costs for 15 years is not appropriate and contrary to good regulatory practice.
- The election of the ten-year deferred rebasing period in the MAADs Handbook was intended to promote consolidation in the electricity sector in Ontario and to allow consolidating utilities to recover transaction and integration costs. There was no mention of natural gas in the MAADs Handbook, and as there are only three natural gas utilities in the Province, there was no need to incent consolidation in the natural gas sector.

SEC argued that the applicants' claim that they needed time to complete integration and realize savings was not supported by the evidence, and there is therefore no rationale for a ten year deferred rebasing period. SEC noted that the total cost of consolidation is expected to be $150 million, and in the first year, the costs exceed the achieved savings by $8 million as per the applicants' evidence.[21] By the end of 2020, the costs are expected to exceed the shortfall by only $4 million, after which point the cumulative savings exceed the costs for the duration of the deferred rebasing period. SEC further noted that this calculation excluded the $5.2 million in annual savings already achieved by the end of 2017 as a result of combining certain activities of Enbridge Gas and Union Gas.[22] SEC further noted that the consolidation does not involve substantial transaction costs, as they are both already owned by the same parent company.

[21] EB-2017-0306, Exhibit B, Tab 1, Attachment 12.
[22] Transcript Volume 1, pages 67-68.

SEC also disagreed that it was appropriate for the applicants to deduct $410 million in stated benefits from the savings calculation in order to earn the allowed ROE. This approach pushes the net benefits to Amalco until the later years (at year eight of the ten-year deferred rebasing period). SEC argued that this approach is based on the assumption that the expected savings of $680 million as a result of the amalgamation over the ten-year period and the standalone assumptions used to calculate the $410 million ratepayer benefit are reasonable. SEC submitted that neither of these assertions is credible.[23] A number of other intervenors (APPrO, FRPO, CCC, LPMA and CME) agreed with SEC.

Intervenors and OEB staff also raised concerns about cost allocation and the true-up of average consumption. They submitted that there are existing inequities with respect to the allocation of costs that need to be corrected. Although Union Gas has agreed to review costs allocated to the Panhandle Reinforcement project, intervenors and OEB staff argued that to make selected adjustments for certain assets now while leaving other adjustments until 2029 would not be fair to the overall customer base. Energy Probe argued that the lengthy period between rebasing and the many cost allocation issues will create rates that would no longer be considered just and reasonable.[24] In reply argument, the applicants proposed to prepare cost allocation studies for each of the years 2022 and 2026 using OEB-approved methodologies, and indicated their willingness to consider changes to cost allocation with the expectation that there would be no impact on the revenue requirement.

The City of Kitchener (Kitchener) noted that its transportation demand charge has increased by 92% over a five-year period. If a ten-year deferred rebasing period was approved, Kitchener would not be able to resolve its cost allocation issues, and the significant rate increases associated with some recent large infrastructure projects of Union Gas would be included in Kitchener's rates for a further ten years.

OEB staff noted that the average use model for Enbridge Gas had a structural break in 2016 and such issues would only be examined at rebasing, and that a ten-year deferred rebasing period was therefore not appropriate.

As a result, a number of intervenors requested immediate rebasing (SEC, FRPO, CCC, LPMA, IGUA, Energy Probe, Kitchener, BOMA and APPrO) and argued that the OEB should require Amalco to file a rebasing application for 2021 rates. They suggested that in the meantime, the two utilities could continue with their respective IR plans or Enbridge Gas could adopt the Price Cap IR of Union Gas.

[23] SEC submission, pages 20-21.
[24] Energy Probe submission, page 3.

In support of immediate rebasing, several intervenors cited the Settlement Agreement in Union Gas' IRM Framework Application[25] which required Union Gas to file a cost-of-service filing in 2019 regardless of whether Union Gas applies to set rates for 2019 on a cost-of-service basis.

Intervenors noted that Enbridge Gas made an equivalent commitment in the oral hearing of its Custom IR application.[26] Intervenors (SEC, IGUA, APPrO and Kitchener) submitted that the utilities should not be allowed to renege on those commitments. The applicants disagreed with this interpretation of the Settlement Agreement and argued that it does not state when Union Gas will rebase but what Union Gas will do when it does rebase. The applicants argued that until the OEB has determined when rebasing will occur, it is not possible to conclude that Union Gas' agreement to prepare a full cost of service had been triggered. The applicants also argued that Enbridge Gas' evidence in its proceeding was given in the context of the Union Gas Settlement Agreement and was based on the expectation that the two utilities would continue to operate individually rather than in the context of a proposed amalgamation.[27]

In response to the suggestion of immediate rebasing, the applicants argued that the recommended approach was contrary to OEB policies that focus on incentives, outcome and performance. The applicants cited one of the key principles of the RRF, which refers to strong incentives to enhance utility performance.[28]

Alternatively, if the OEB was considering a deferred rebasing period, a majority of intervenors suggested a maximum deferred rebasing period of five years, although some argued for four or six years. OEB staff noted that the majority of Amalco's integration would be completed by 2024 and the utility would be in a position to file a rebasing application for 2025 rates.[29] In reply, the applicants emphasized the need for a ten-year deferral period as that is what they require to complete the amalgamation thoughtfully, thoroughly and effectively.

OEB Findings

The OEB approves a deferred rebasing period of five years. The next rebasing application will therefore be expected for 2024 rates. The OEB finds that five years provides a reasonable opportunity for the applicants to recover their transition costs.

[25] EB-2013-0202.
[26] EB-2012-0459.
[27] Applicants Reply, pages 33-34, paras 97-99
[28] Ibid, para 86.
[29] OEB staff submission, page 9

The OEB's policy of permitting a deferred rebasing period of up to ten years was adopted to incent the consolidation of electricity distributors.

For the gas utilities, Union Gas last rebased for 2013 and Enbridge Gas last rebased through a Custom IR application with a term from 2014 to 2018. To allow a further ten years before rebasing would result in 15 years without a rebasing application. During the last rate setting frameworks, both Union Gas and Enbridge Gas earned more than the OEB-approved return as evidenced by the earnings sharing mechanisms for both utilities. Customers will not benefit from any efficiency gains from this previous period until the end of the rebasing period.

The OEB agrees that the RRF is focused on the delivery of outcomes. These are assessed in part through the use of benchmarks which have been developed and applied for several years in the electricity distribution sector. In the absence of benchmarking on which to assess the performance of the applicants, and the resulting outcomes for their customers, the OEB has determined that 15 years is too long to go without a full review of their costs.

The OEB finds the wording in the Settlement Agreement for Union Gas' IRM Framework is not clear with respect to the rate-setting for 2019, though the wording implies there was an expectation that Union Gas would rebase its rates for 2019. The OEB is granting a five year deferred rebasing period consistent with its historic practice for other MAADs applications, and therefore is not requiring Union Gas to rebase for 2019.

The Settlement Agreement also required Union Gas to file costs at the time of rebasing. The OEB notes that the applicants did file significant historic and forecast costs as part of this application. Furthermore, in this Decision there are several findings that require the filing of costs as follows:

- As discussed in Section 5.9, the OEB is requiring Amalco to file a cost allocation study in 2019 to reflect the costs of certain large projects.
- Section 5.5 requires Amalco to file a consolidated utility system plan to support any application for an ICM for 2021 rates and beyond.
- Amalco is required to track the actual costs and amounts recovered through rates related to the Parkway Delivery Obligation during the deferred rebasing period, as discussed in Section 6.1.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

The impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity) will be assessed based on the applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

The impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will also be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and integration costs) to implement the consolidation transaction

In the Combined Proceeding decision, the OEB made it clear that the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test. While there may not be a premium involved with mergers, the OEB will nevertheless consider the financial viability of the newly consolidated entity.

Electricity distribution rates are currently based on a return on the historic value of the assets. If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity. In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed. Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

Incremental transaction and integration costs are not generally recoverable through rates. Distributors have indicated that these costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB issued a report on March 26, 2015 titled "*Rate-making Associated with Distributor Consolidation*" (2015 Report). In this report, the OEB has provided the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction. This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.

*****

The OEB considers that certain aspects of a consolidation transaction are not relevant in assessing whether the transaction is in the public interest, either because they are out of scope, or because the OEB has other approaches and instruments for ensuring that statutory objectives will be met. Accordingly, the OEB will not require applicants to file evidence on the following matters as part of a consolidation application.

1. Deliberations, activities, and documents leading up to the final transaction agreement

As set out in the Combined Proceeding decision, and confirmed in recent decisions,[4] the question for the OEB is neither the why nor the how of the proposed transaction. The application of the "no harm" test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB's statutory objectives.

The OEB determined in the Combined Proceeding decision that it is not the OEB's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB. Accordingly, the OEB will not consider, whether a purchasing or selling utility could have achieved a better transaction than that being put forward for approval in the application.

Also as set out in the Combined Proceeding decision, the OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans nor the negotiating strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB.

Applicants and stakeholders should not file any of the following types of information as they are not considered relevant to the proceeding:

- Draft share purchase agreements and other draft confidential agreements and documents utilized in the course of the negotiation process

[4] Hydro One Inc./Norfolk Power Distribution Inc. Decision and Order and Procedural Order No. 8 – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Woodstock Hydro Services Inc. Decision and Procedural Order No. 4 – OEB File No. EB-2014-0213

Enbridge Gas Distribution - Earnings & Return Above OEB Approved ROE

	A	B	C	D	E
	ROE above OEB Approved (3)	**Gross Earnings Above OEB Approved ROE ($M) (4)**	**ROE with Deadband Above OEB approved ROE (1)**	**ROE Deadband**	**Common Equity ($M) (2)**
2019	1.49%	95.9	-0.01%	1.50%	4,730.0
2020	0.20%	13.3	-1.30%	1.50%	4,882.3
2021	0.83%	46.5	-0.67%	1.50%	4,119.8
2022	0.70%	52.7	-0.80%	1.50%	5,537.3
2023	TBD	TBD	TBD	TBD	TBD
Total		***208.4***			

(1) 1.8-SEC-85, Attachment 1, p.13-16, Ln 22

(2) 1.8-SEC-85, Attachment 1, p.13-16, Ln 19

(3) C + D

(4) (A x E)/73.5%

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

1-9-1, p.21; 9-2-1, p.22

Question(s):

With respect to integration capital:

a) Please provide the 2024 revenue requirement, broken down into each major component (rate base, return on capital, depreciation, taxes), for all integration capital that Enbridge seeks to add to the rate base.

b) Please also provide the Tax Variance Deferral Account (TVDA) balance related to integration capital.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

a) Please see below for the 2024 forecast revenue requirement applicable to integration capital:

($ millions)	2024 Revenue Requirement	
Rate Base	112	/u
Depreciation (1)	15	/u
Interest Expense	3	/u
Return on Capital	5	/u
Income Tax	5	/u
Total (2)	28	/u

Notes:
(1) Depreciation per the revised depreciation rates proposed in Exhibit 2, Tab 5, Schedule 4, Attachment 1. /u
(2) Revenue requirement would be $47 million with existing depreciation rates reflected. /u

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 2, Tab 6, Section 5.4.7 (REWS)

Question(s):

a) Please provide a list of all properties that were sold in each year 2019 through 2022 and provide the net (of fees) sale price.

b) Please provide a list of the forecast sales of properties in 2023 and 2024 and the current assessed value of those properties.

c) Please provide a list of the properties forecast to be purchased in 2023 and 2024 and the current actual or forecast cost of those properties.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023.

a) Properties sold in the years 2019 through 2022 are as follows:

- 2019 to 2021 - None
- 2022 - 3401 Schmon Parkway, Thorold. Net sale price $12,246,500

b) The properties forecast for disposition in 2023 and 2024 are as follows: /u

- 2023 - 335 Prichard Rd, Hamilton. Sold, net sale price $3,033,250
- 2024 - 90 Bill Leathem Drive, Nepean, South Merivale Operation Centre (SMOC), $6.3M estimate

Upon disposition of a property, Enbridge Gas calculates a separate gain (or loss) for the land and building by apportioning the sale proceeds between the land and building in accordance with U.S. GAAP. As prescribed in the OEB's Uniform System of Accounts for Class A Gas Utilities, the gain (or loss) on the sale of land is recorded to income. The gain (or loss) on the building sale is captured in accumulated depreciation and is recovered through depreciation expense over the remaining life of the assets left within the group, based on subsequent depreciation studies.

Enbridge Gas has forecasted dispositions of property at net book value, as gains or losses on disposition are only determined at the time of sale.

c) One property is forecasted for purchase in 2023: 209 Cambridge Ave, Iroquois Falls at a forecast price of $61,000. No properties are forecast to be purchased in 2024.

4. Year-over-Year Variance Analysis of Capital Expenditures 2019 to 2024 - Enbridge Gas

12. The following sections of this Exhibit provide detailed variance explanations for Enbridge Gas's capital expenditures from 2019 to the 2024 Test Year Forecast. Table 6 summarizes the expenditures from 2019 to 2024.

Table 6
Utility Capital Expenditures by Asset Class 2019 Actual -2024 Test Year

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Compression Stations	EGI	25.5	26.5	42.3	87.7	239.2	38.9	
2	Customer Connections	EGI	190.4	178.7	260.7	220.7	220.4	249.2	
3	Distribution Pipe	EGI	175.1	192.8	447.2	458.5	261.9	368.3	
4	Distribution Stations	EGI	39.7	61.4	91.2	106.6	149.3	120.6	
5	Fleet & Equipment	EGI	26.3	20.2	26.7	30.6	25.5	35.0	
6	Growth - Distribution System Reinforcement	EGI	144.1	70.0	48.5	52.6	54.9	105.1	
7	Real Estate & Workplace Services	EGI	42.0	38.3	70.5	118.7	52.1	56.6	
8	Technology Information Services (TIS)	EGI	48.9	22.7	22.8	39.4	63.7	112.4	
9	Transmission Pipe and Underground Storage	EGI	20.3	33.5	79.5	102.5	280.7	171.7	
10	Utilization	EGI	99.3	62.9	80.7	120.3	136.5	146.5	
11	Extended Alliance Fixed Overhead	EGI	17.8	19.5	25.4	21.3	21.7	21.9	
12	Capitalized Overheads	EGI	215.2	220.9	0.0	0.0	0.0	0.0	
13	Integration Capital	EGI	21.7	39.8	87.5	41.6	43.6	0.0	
14	Community Expansion	EGI	17.1	20.9	17.4	20.7	14.0	24.4	
15	Other	EGI	3.9	(0.9)	10.5	22.9	42.0	40.8	/u
16	Total		1,087.4	1,007.2	1,310.8	1,444.3	1,605.7	1,491.3	/u

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC
(3) Overheads are included in the Asset Classes starting in 2021

Table 6
Utility Capital Expenditures by Asset Class 2019 Actual -2024 Test Year

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Actual (d)	2023 Bridge Year (e)	2024 Test Year (f)	/u
1	Compression Stations	EGI	25.5	26.5	42.3	106.8	321.8	46.3	/u
2	Customer Connections	EGI	190.4	178.7	260.7	297.0	286.3	304.1	/u
3	Distribution Pipe	EGI	175.1	192.8	447.2	477.5	237.5	357.1	/u
4	Distribution Stations	EGI	39.7	61.4	91.2	97.1	67.5	83.5	/u
5	Fleet & Equipment	EGI	26.3	20.2	26.7	30.6	8.9	31.5	/u
6	Growth - Distribution System Reinforcement	EGI	144.1	70.0	48.5	69.4	55.1	85.2	/u
7	Real Estate & Workplace Services	EGI	42.0	38.3	95.0	66.6	63.0	63.0	/u
8	Technology Information Services (TIS)	EGI	48.9	22.7	22.8	28.1	47.1	102.4	/u
9	Transmission Pipe and Underground Storage	EGI	20.3	33.5	79.5	62.6	79.0	69.2	/u
10	Utilization	EGI	99.3	62.9	80.7	98.4	160.7	152.3	/u
11	Extended Alliance Fixed Overhead	EGI	17.8	19.5	25.4	27.0	25.6	39.8	/u
12	Capitalized Overheads	EGI	215.2	220.9	0.0	0.0	0.0	0.0	
13	Integration Capital	EGI	21.7	39.8	63.0	26.5	20.0	0.0	/u
14	Community Expansion	EGI	17.1	20.9	17.4	14.2	20.6	11.2	/u
15	Other	EGI	3.9	(0.9)	10.5	1.1	34.3	124.6	/u
16	Total		1,087.4	1,007.2	1,310.8	1,402.9	1,427.2	1,470.3	/u

Notes:
(1) Capital expenditures are shown on an annual basis
(2) Expenditures are net of contributions and include IDC
(3) Overheads are included in the Asset Classes starting in 2021
(4) Panhandle Regional Expansion Project capex reductions of $34.2M in 2022, $22.7M in 2023 and $194.9M in 2024 /u

Table 1
Utility In-Service Capital Expenditures by Asset Class

Line No	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Compression Stations	EGI	11.5	40.5	51.8	62.6	262.1	21.0	41.4	164.1	32.3	18.7
2	Customer Connections	EGI	157.8	221.7	268.6	282.2	220.4	249.2	249.2	250.3	260.6	250.1
3	Distribution Pipe	EGI	209.4	127.0	387.2	505.2	257.5	341.5	350.8	304.2	292.3	316.4
4	Distribution Stations	EGI	32.8	100.2	82.7	68.4	159.5	122.6	116.4	110.6	112.0	116.7
5	Fleet & Equipment	EGI	28.8	20.3	25.3	35.1	25.5	35.0	36.4	40.5	53.6	52.3
6	Growth - Distribution System Reinforcement	EGI	134.9	77.2	49.7	90.7	51.3	102.5	185.6	41.2	5.9	12.7
7	Real Estate & Workplace Services	EGI	41.3	19.4	72.0	58.8	15.7	93.7	79.5	121.5	40.0	88.5
8	Technology Information Services (TIS)	EGI	51.6	34.0	21.5	37.7	52.0	83.2	59.2	147.5	48.1	54.1
9	Transmission Pipe and Underground Storage	EGI	10.8	42.9	95.0	57.9	295.0	168.4	49.5	273.6	75.0	130.7
10	Utilization	EGI	133.0	65.4	90.2	93.9	136.5	146.5	148.5	153.2	166.3	168.4
11	EA Fixed Overhead	EGI	25.9	27.0	19.8	28.2	21.7	21.9	22.2	22.5	22.9	23.2
12	Capitalized Overheads	EGI	180.5	200.6	-	-	-	-	-	-	-	-
13	Integration Capital	EGI	18.8	18.7	75.4	67.4	59.4	-	-	-	-	-
15	Other	EGI	15.5	30.8	11.5	4.3	12.2	30.0	21.6	17.0	7.0	7.3
16	Community Expansion	EGI	8.9	9.7	2.1	3.2	42.8	41.1	36.3	35.7	49.7	36.1
17	Union Unregulated Allocations		(3.6)	(7.2)	(12.9)	(36.2)	-	-	-	-	-	-
18	Total		1,057.8	1,028.2	1,239.9	1,359.3	1,611.5	1,456.5	1,396.7	1,681.9	1,165.6	1,275.2

Table 1
Utility In-Service Capital Expenditures by Asset Class

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Actual (d)	2023 Bridge Year (e)	2024 Test Year (f)	2025 Forecast (g)	2026 Forecast (h)	2027 Forecast (i)	2028 Forecast (j)	
1	Compression Stations	EGI	11.5	40.5	51.8	62.6	362.7	43.9	53.5	17.8	26.8	18.7	/u
2	Customer Connections	EGI	157.8	221.7	268.6	282.2	286.3	304.0	248.4	257.8	254.1	250.1	/u
3	Distribution Pipe	EGI	209.4	127.0	387.2	505.2	272.4	350.7	356.2	299.9	250.2	316.4	/u
4	Distribution Stations	EGI	32.8	100.2	82.7	68.4	58.7	101.2	133.6	91.4	92.6	116.7	/u
5	Fleet & Equipment	EGI	28.8	20.3	25.3	35.1	8.9	31.5	35.4	40.1	45.7	52.3	/u
6	Growth - Distribution System Reinforcement	EGI	134.9	77.2	49.7	90.7	45.4	75.5	219.9	34.2	56.9	12.7	/u
7	Real Estate & Workplace Services	EGI	41.3	19.4	96.5	58.8	32.1	19.2	72.9	203.7	23.2	88.5	/u
8	Technology Information Services (TIS)	EGI	51.6	34.0	21.5	37.7	33.7	68.9	53.4	143.1	44.9	54.1	/u
9	Transmission Pipe and Underground Storage	EGI	10.8	42.9	95.0	57.9	44.8	52.4	174.8	177.1	292.6	130.7	/u
10	Utilization	EGI	133.0	65.4	90.2	93.9	160.7	152.3	160.2	173.0	152.0	168.4	/u
11	EA Fixed Overhead	EGI	25.9	27.0	19.8	28.2	25.6	39.8	40.8	41.9	43.0	23.2	/u
12	Capitalized Overheads	EGI	180.5	200.6	-	-	-	-	-	-	-	-	
13	Integration Capital	EGI	18.8	18.7	50.9	67.4	22.7	-	-	-	-	-	/u
15	Other	EGI	15.5	30.8	11.5	4.3	10.6	22.2	13.8	26.8	24.4	7.3	/u
16	Community Expansion	EGI	8.9	9.7	2.1	3.2	4.5	52.0	61.6	28.3	28.0	36.1	/u
17	Union Unregulated Allocations		(3.6)	(7.2)	(12.9)	(36.2)	-	-	-	-	-	-	
16	Total		1,057.8	1,028.2	1,239.9	1,359.3	1,369.1	1,313.6	1,624.7	1,535.0	1,334.4	1,275.2	/u

Excludes in-service additions for PREP of $252M in 2024 and $6.8M in 2025. /u

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102291	2023	10

Investment Name: Contract Market Harmonization

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. In order to harmonize contract market rates, services must also be harmonized. Enbridge believes that harmonizing and aligning services for the contract market will improve the customer experience for contract customers by reducing the number of systems they must transact in, aligning policies across rate zones, and simplifying processes. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the approved rates and services in the systems listed below. By implementing this project coincident with the Contract Market Systems – Technology Obsolescence project, the investment of capital is optimized.

Assets: TIS Business Solutions. EnTRAC, URICA, Enerline, CARE, ConTrax, GDAR, SAP- CIS, SAP-ERP, Oracle Financials, Data Marts are examples of the systems impacted

Related Program: Contract Market Systems - Technology Obsolescence #736942, Rates and Service Harmonization Project #76081

Recommended Alternative Description

Scope of Work: Currently, Enbridge Gas Inc (EGI) has 3 different rate zones (EGD, Union North, Union South), 11 separate service designs and 43 rate classes. This results in complex business and accounting processes. This project will implement changes to several EGI business applications to implement harmonized services, rate zones, and rate classes.

This project, in conjunction with the Contract Market - Technology Obsolescence Project, is required to provide consistent services with common design elements for customers in all areas of the franchise. The simplified, consistent services will enhance the customer experience, provide more flexibility for customers, and reduce the complex variations in the existing services and rates. Contract market harmonization will facilitate harmonized business processes, reduced system complexity, and will reduce the level of effort associated with ongoing business and TIS support. Detailed information regarding the service and rate harmonization and the associated benefits will be filed with EGI's 2024 rebasing application.

Several business applications are impacted based upon the changes proposed:
-ConTrax/CARE/GDAR/Enerline - The Union rate zone business applications that perform contracting, billing and gas management/nominations functions, including customer facing portals.
-EnTRAC/Urica/GDAR – The EGD rate zone business applications that perform contracting and gas management/nominations functions, including customer facing portals.

This functionality will be enabled in conjunction with the Contract Market Systems - Technology Obsolescence project, which will coincidentally integrate the above legacy company applications and replace aging technologies. These business applications must be integrated to allow for the harmonization of rate zones, rate classes and services as well as a single customer portal. If the applications are not integrated, EGI will need to make changes to multiple applications to align them with the harmonized services and business processes. A single customer portal would remain a requirement regardless of the underlying business applications. In addition, some of the proposals for service harmonization may not be able to be implemented. For example, the scenario where customers or contracts cross between the existing rate zones. In addition to the primary business applications, there will also be changes required to downstream processes and applications such as gas accounting, QRAM, and financial reporting to align with the harmonized rates and services.

This project will follow TIS project methodologies as developed and governed by the Project Management Office.

Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: EGI currently has 3 Rate Zones, 11 Separate Service Designs and 43 Rate Classes. This project will implement the required changes to enable service and rate harmonization.

Project Timing & Execution Risks:
-Project expected to start late 2023, and will continue into 2024 pending the approval of Rate and Service Design by the OEB as part of the 2024 Rebasing Application. A key dependency is the Contract Market - Technology Obsolescence Project. In order to harmonize services, EGI must consolidate and modernize the contract rate billing, contracting, GDAR and gas management/nominations applications. Target implementation date is Q2 2026. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
-Risks include resource constraints, competing priorities, OEB approval of service and rate harmonization as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Contract Market Harmonization	$ 14,760,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 2,000,000	$ 5,000,000	$ 5,000,000	$ 2,760,000	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736081	2023	10
	Investment Name		
	General Service Rebasing Changes		

Investment Description

Issue/Concern/Opportunity: The OEB MAADs decision specified that EGI shall file a proposal for rate harmonization in its next rebasing application. EGI believes that harmonizing rates will improve the customer experience for general service customers by simplifying rates, processes, and improved cost transparency. If the proposal filed as part of 2024 Rebasing is approved, this project will be required to implement the proposal in the EGI systems listed below.

Assets: TIS Business Solutions. CIS-SAP, Kubra, SAP-ERP, Oracle Financials, EnTRAC, ConTrax, GDAR, MyAccount, Data Marts (BBDM, CTDS, BW, EDW, etc), Guardian, Load Gathering, Synergee, Get Connected are examples of the systems impacted.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Currently, Enbridge Gas Inc. (EGI) has three different rate zones (EGD, Union South and Union North) and six general service customer classes across eight rate categories. This results in complex business and accounting processes. This project will implement changes to several EGI systems to implement a harmonized model with a single rate zone for EGI, two customer classes (rate categories – Small Demand and General Demand) and harmonized rates. This will simplify rates for customers and related business and accounting processes such as QRAM. This project will follow TIS project methodologies as developed and governed by the Project Management Office.

Benefits include improved customer experience due to simplification of rates and improved cost transparency, business process simplification resulting from one set of terms and conditions of service across entire EGI franchise area, simplification of accounting processes including QRAM, forecasting, financial reporting, and easier to administer regulatory application and OEB review processes.

Resources: Project Manager, Business Analysts, Business Systems Support Team, Customer Care SMEs, Regulatory SMEs, Finance SMEs, TIS SMEs, Energy Services SMEs, Finance SMEs Enterprise Architecture, Solutions Architecture, Data & Analytics, Report Developers, AMS provider, Solutions Integrator, Audit, Testing, Organizational Change Management (OCM)

Solution Impact: This project will implement the required changes to enable a single rate zone for EGI with two customer classes (Rate Categories – Small Demand and General Demand) and the harmonization of general service rates.

Project Timing & Execution Risks:
-Project to start no later than January 2024, with approval from the OEB of General Service Rate Harmonization. Target implementation date Q2 2025. Project milestones for design, build, test and delivery to be developed once project approved, team established, and project initiated.
-Risks include resource constraints, competing priorities, OEB approval of harmonization as submitted by EGI.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
General Service Rebasing Changes	$ 16,000,000

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 14,000,000	$ 2,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

Line No.	Investment Code	Appendix A Investment Name	AMP Planning Group	2023-2032 Forecast Including Overheads	2023-2032 Overhead Allocation	In Service Date
	(a)	(b)	(c)	(d)	(e)	(f)
	Asset Class (EGI) - Compression Stations					
1	48715	Dawn C Compression Lifecycle	Significant Invetsments (>$10M) - Fixed Timing	$166,338,152	$41,178,152	2027
2	48732	Waubuno Compression Lifecycle	Value Driven - Fixed Timing	$29,218,620	$6,141,720	2025
3	100901	Dawn to Corunna	Value Driven - Fixed Timing	$200,337,430	$45,845,900	2023
4	734634	Dawn to Corunna (Dawn Tie-in)	Value Driven - Fixed Timing	$105,753,129	$23,718,491	2023
	Asset Class (EGI) - Distribution Pipe					
5	10088	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	Value Driven - Fixed Timing	$20,896,371	$4,797,127	2022
6	10290	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	Value Driven - Fixed Timing	$25,033,190	$5,478,112	2024
7	10293	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	Value Driven - Fixed Timing	$121,804,143	$26,503,360	2025
8	10294	St. Laurent Phase 4 - East/West (NPS12 Steel)	Value Driven - Fixed Timing	$53,906,876	$11,800,108	2024
9	11443	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.	Value Driven - Value Framework	$30,613,585	$7,603,920	2026, subject to EDIMP assessment
10	100295	Div_04: NPS 8 Port Stanley, London, Replacement	Value Driven - Fixed Timing	$18,916,863	$4,025,457	2025, subject to EDIMP assessment
11	100339	A10: Wilson Avenue, Toronto, VSM Replacement	Executing - Re-Optimize	$106,992,932	$25,192,932	2026/2031, refer to Exhibit I.2.6- ED-100
12	503350	Moulton Replacement BU	Executing - Re-Optimize	$18,165,905	$3,813,905	2025
13	740604	NPS20 KOL - Parliament St.	Mandatory - Fixed Timing	$13,131,787	$3,014,631	2023
	Asset Class (EGI) - Distribution Stations					
14	13034	SCRW:Station-Renewal In-Place	Mandatory - Fixed Timing	$28,244,162	$6,171,173	2025
15	503369	Lisgar Station	Executing - Re-Optimize	$20,124,611	$4,242,407	2025
16	734676	SARN: 13F-220R Vidal St	Value Driven - Value Framework	$17,192,992	$4,712,992	2031
17	735022	Sarnia Industrial Station 2029 Rebuild	Value Driven - Fixed Timing	$14,849,863	$3,849,863	2029
	Asset Class (EGI) - Growth					
18	1024	NW 6581 Ottawa Reinforcement Phase 2 SRP	Mandatory - Fixed Timing	$70,698,549	$17,209,549	2029
19	30542	SRP_Southeast_Owen Sound_County Rd 40_Reinforcement_NPS12_11800m_4670kPa	Mandatory - Fixed Timing	$33,636,531	$7,236,531	2025
20	30579	SRP_Southwest_Wonderland_New STN & MOP Upgrade	Mandatory - Fixed Timing	$20,506,933	$4,306,933	2025
21	100703	SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa	Mandatory - Fixed Timing	$45,292,234	$11,283,270	2027
22	736259	Hamilton Reinforcement Project	Mandatory - Fixed Timing	$125,821,854	$26,713,062	2025
23	736975	Enbridge Gas Distribution System Hydrogen Feasibility Study	Value Driven - Fixed Timing	$15,315,942	$3,398,275	2022

Line No.	Investment Code	Appendix A Investment Name	AMP Planning Group	2023-2032 Forecast Including Overheads	2023-2032 Overhead Allocation	In Service Date
	Asset Class (EGI) - LNG					
24	48709	Hagar KVGR and Cycle Mix Cooler	Value Driven - Value Framework	$24,740,190	$5,648,190	2032
25	48714	Hagar Cold Box	Value Driven - Value Framework	$14,401,282	$3,401,282	2032
26	49955	Hagar JVG Compressor Upgrade	Value Driven - Value Framework	$20,873,854	$4,781,854	2032
	Asset Class (EGI) - Real Estate & Workplace Services					
27	3640	Station B New Building	Value Driven - Fixed Timing	$38,590,879	$8,590,879	2025
28	8782	VPC Core and Shell	Value Driven - Value Framework	$35,420,035	$9,420,035	2031
29	100621	Dawn Administrative Centre	Value Driven - Value Framework	$16,349,278	$4,349,278	2028
30	101136	New London Site	Executing - Re-Optimize	$49,500,658	$11,959,058	2026
31	737272	Kennedy Road New Build	Value Driven - Value Framework	$49,647,957	$11,803,457	2026
32	737374	Ottawa - New Building	Value Driven - Value Framework	$46,337,933	$10,498,150	2026
33	737754	Thorold Operations Centre - New Building	Value Driven - Value Framework	$21,533,430	$5,033,430	2026
34	739714	GTA East - New Build - Peterborough	Value Driven - Value Framework	$14,722,478	$3,722,478	2024
35	739715	GTA West - New Build - Halton Hills	Value Driven - Value Framework	$42,675,572	$9,790,356	2026
	Asset Class (EGI) - TIS					
36	102291	Contract Market Harmonization	Value Driven - Value Framework	$19,195,783	$4,335,783	2026
37	102364	Records Management Technology Obsolescence (2024-2026)	Value Driven - Value Framework	$23,566,261	$5,516,261	2026
38	736081	General Service Rebasing Changes	Value Driven - Value Framework	$17,914,329	$3,914,329	2025
39	736942	Contract Market Systems - Technology Obsolescence	Mandatory - Fixed Timing	$69,786,961	$15,776,961	2026
	Asset Class (EGI) Transmission Pipe & Underground Storage					
40	48654	Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	Mandatory - Fixed Timing	$251,357,572	$63,082,988	2027
41	49758	Panhandle Regional Expansion Project	Mandatory - Fixed Timing	$224,328,497	$47,088,489	2024
42	100086	Panhandle Line Replacement	Value Driven - Fixed Timing	$37,899,145	$8,128,866	2025
43	100699	Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	Mandatory - Fixed Timing	$332,803,728	$86,169,476	2029
44	735972	PREP: NPS 36 looping to Comber Transmission	Mandatory - Fixed Timing	$95,496,455	$25,496,455	2030
45	736923	Panhandle Regional Expansion Project - Leamington Interconnect	Mandatory - Fixed Timing	$118,751,452	$28,443,901	2026
46	740055	Panhandle Regional Expansion Project - Dawn Facilities	Mandatory - Fixed Timing	$92,044,573	$19,910,796	2025

Table 1
Utility Property, Plant & Equipment - Continuity of Gross Assets

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Opening Gross Property, Plant and Equipment	EGI	19,467.7	20,402.8	21,259.9	22,221.4	23,535.2	24,831.5	/u
2	Opening Balance Adjustments (1)	EGI	0.0	0.0	0.0	10.4	(69.6)	(317.5)	
3	In-service Additions	EGI	1,056.2	1,023.4	1,211.7	1,442.3	1,521.7	1,503.9	/u
4	Retirements and Disposals	EGI	(121.0)	(166.2)	(250.2)	(139.0)	(155.8)	(226.1)	/u
5	Adjustments and Other	EGI	0.0	0.0	0.1	0.1	0.0	0.0	
6	Closing Property, Plant and Equipment	EGI	20,402.8	21,259.9	22,221.4	23,535.2	24,831.5	25,791.8	/u
7	Average of Monthly Averages	EGI	19,765.5	20,582.1	21,539.8	22,663.3	23,874.8	24,902.9	/u
8	Variance of Gross PPE to Prior Year			857.1	961.5	1,313.8	1,296.3	960.3	/u
9	Variance of Avg of Monthly Avg to Prior Year			816.6	957.7	1,123.5	1,211.6	1,028.1	/u

Notes:
(1) Includes asset harmonization and unregulated cost allocation adjustments.

Table 1
Utility Property, Plant & Equipment - Continuity of Gross Assets

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	/u
1	Opening Gross Property, Plant and Equipment	EGI	19,467.7	20,402.8	21,259.9	22,221.4	23,402.3	24,643.7	/u
2	Opening Balance Adjustments (1)	EGI	0.0	0.0	0.0	11.7	0.0	(241.3)	/u
3	In-service Additions	EGI	1,056.2	1,023.4	1,211.7	1,379.3	1,428.1	1,300.9	/u
4	Retirements and Disposals	EGI	(121.0)	(166.2)	(250.2)	(210.1)	(170.8)	(176.3)	/u
5	Adjustments and Other	EGI	0.0	0.0	0.1	0.0	(15.9)	(15.3)	/u
6	Closing Property, Plant and Equipment	EGI	20,402.8	21,259.9	22,221.4	23,402.3	24,643.7	25,511.6	/u
7	Average of Monthly Averages	EGI	19,765.5	20,582.1	21,539.8	22,585.9	23,716.5	24,736.3	/u
8	Variance of Gross PPE to Prior Year			857.1	961.5	1,180.9	1,241.4	867.9	/u
9	Variance of Avg of Monthly Avg to Prior Year			816.6	957.7	1,046.1	1,130.6	1,019.8	/u

Note:
(1) Includes asset harmonization and unregulated cost allocation adjustments.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 2, Tab 6, Section 5.4.7 (REWS)

Question(s):

a) Please provide a list of all properties that were sold in each year 2019 through 2022 and provide the net (of fees) sale price.

b) Please provide a list of the forecast sales of properties in 2023 and 2024 and the current assessed value of those properties.

c) Please provide a list of the properties forecast to be purchased in 2023 and 2024 and the current actual or forecast cost of those properties.

Response:

Enbridge Gas has assumed that the correct reference for this interrogatory is Exhibit 2, Tab 6, Schedule 2, Section 5.4.7.

a) Properties sold in the years 2019 through 2022 are as follows:

- 2019 to 2021 - None
- 2022 - 3401 Schmon Parkway, Thorold. Net sale price $12,246,500

b) The properties forecast for disposition in 2023 and 2024 are as follows:

- 2023 - 335 Prichard Rd, Hamilton. Sold, net sale price $3,033,250
- 2024 - 500 Coventry Rd, Ottawa. Sold, net sale price $19,782,500
- 2024 - 90 Bill Leathem Drive, Nepean, South Merivale Operation Centre (SMOC), $6.3M estimate
- 2024 - 572 Neal Drive, Peterborough, $1.7 to $2.2M estimated range
- 2024 - 520 Thompson St, Cobourg, $2.03 to $2.52M estimated range

c) One property is forecasted for purchase in 2023: 209 Cambridge Ave, Iroquois Falls at a forecast price of $61,000. No properties are forecast to be purchased in 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit 2, Tab 6, Section 5.4.7 (REWS)

Question(s):

a) Please provide a list of all properties that were sold in each year 2019 through 2022 and provide the net (of fees) sale price.

b) Please provide a list of the forecast sales of properties in 2023 and 2024 and the current assessed value of those properties.

c) Please provide a list of the properties forecast to be purchased in 2023 and 2024 and the current actual or forecast cost of those properties.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023.

a) Properties sold in the years 2019 through 2022 are as follows:

- 2019 to 2021 - None
- 2022 - 3401 Schmon Parkway, Thorold. Net sale price $12,246,500

b) The properties forecast for disposition in 2023 and 2024 are as follows: /u

- 2023 - 335 Prichard Rd, Hamilton. Sold, net sale price $3,033,250
- 2024 - 90 Bill Leathem Drive, Nepean, South Merivale Operation Centre (SMOC), $6.3M estimate

Upon disposition of a property, Enbridge Gas calculates a separate gain (or loss) for the land and building by apportioning the sale proceeds between the land and building in accordance with U.S. GAAP. As prescribed in the OEB’s Uniform System of Accounts for Class A Gas Utilities, the gain (or loss) on the sale of land is recorded to income. The gain (or loss) on the building sale is captured in accumulated depreciation and is recovered through depreciation expense over the remaining life of the assets left within the group, based on subsequent depreciation studies.

Enbridge Gas has forecasted dispositions of property at net book value, as gains or losses on disposition are only determined at the time of sale.

c) One property is forecasted for purchase in 2023: 209 Cambridge Ave, Iroquois Falls at a forecast price of $61,000. No properties are forecast to be purchased in 2024.