Enbridge Gas Inc.

OEB Staff Compendium

Panel 1 – Enbridge Gas Panel on Energy Transition

EB-2022-0200

July 18, 2023

OEB Staff Compendium for EB-2022-0200 Oral Hearing

Index

TAB 1

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 4, p. 13-14, 18-19, Exhibit 1, Tab 15, Schedule 1, p. 1

Question(s):

Enbridge Gas discusses how the AMP, including the growth asset class incorporates energy transition assumptions. Enbridge Gas notes the increased risk of stranded assets from energy transition and has proposed changes to its deemed capital structure. Enbridge Gas further requests approval of its harmonized customer connection policies.

a) Please describe how Enbridge Gas has considered and attempted to mitigate the risks of stranded assets associated with the proposed capital expenditures identified in its AMP (particularly growth-related capital expenditures including customer connections and distribution/transmission system reinforcement/expansion projects, but also considering system renewal expenditures to extend the service life of assets), related to uncertainty in future volumes or number of customers arising from the energy transition.

b) In Enbridge Gas's opinion, should ratepayers bear 100% of the cost recoveries related to stranded assets?

c) Has Enbridge Gas considered whether the proposal to increase Enbridge Gas's equity ratio may work at cross-purposes to the intent of managing energy transition risk, by increasing rates and potentially increasing the risk of customers exiting the natural gas system?

d) Has Enbridge Gas given consideration to adjustments to its customer connection policies to mitigate the risk of stranded assets associated with new customer connections who may leave the natural gas system before Enbridge's investment is recovered, e.g., by reducing the customer revenue horizon, requiring greater upfront customer contributions, eliminating the free service allowance for residential infills, introducing exit fees for new customers, etc.? If so, please provide details.

Response:

a) Enbridge Gas's proposed 2024 to 2028 AMP capital expenditures are predicated on fulfilling its obligation to (1) maintain a safe and reliable system, (2) connect customers based on OEB-approved connection policies and (3) implement IRP alternatives where technically and economically feasible. Enbridge Gas acknowledges that there exists some uncertainty about how the energy transition will unfold in Ontario; however, this does not absolve Enbridge Gas from the aforementioned obligations, especially when, despite pathway uncertainty, a project's underlying need/constraint has a high degree of certainty (e.g., minimum five-year demand forecast) and /or there is an absence of other technically or economically feasible alternatives.

   Enbridge Gas has taken many steps to mitigate the risk of stranded assets associated with the proposed capital expenditures within and beyond the five-year regulatory plan period. These include:

   - Completing an Energy Transition Scenario Analysis (ETSA) to understand the impacts of energy transition and the associated climate policies on natural gas demand in Enbridge Gas's distribution system.

   - Commissioning the Pathways to Net Zero Emissions in Ontario Study, conducted by Guidehouse to understand how Enbridge Gas's system could play a role in a net-zero future. The study built upon the ETSA work and found that a Diversified scenario achieves net zero with significant savings and more reliability, relative to an electrification scenario. The Diversified scenario would also increase the need for pipeline infrastructure to deliver large quantities of low carbon fuels like hydrogen and RNG. Please see Exhibit 1, Tab 10, Schedule 5.

   - Ongoing review and incorporation of energy transition assumptions into the demand forecasting process for new construction and existing customers replacing gas appliances and updates to annual and peak demand for gas. Please see Exhibit 1, Tab 10, Schedule 4, Table 2.

   - Ongoing updates to the asset management plan to respond to a changing pace of energy transition and to ensure that facilities projects' underlying needs/constraints (e.g., minimum five-year demand forecast) have a high degree of certainty when they are brought forward for approval. Please see Exhibit 1, Tab 10, Schedule 4, paragraph 37.

   - Incorporation of the IRP framework into the asset management process to defer or avoid new infrastructure, where possible, due to uncertainty related to energy transition. Please see Exhibit 1, Tab 10, Schedule 4, paragraph 43.

- Enhancements to the Distribution Integrity Management Program will allow the Company to further optimize its vintage steel main replacement program. Please see Exhibit 1, Tab 13, Schedule 3.

- Ongoing monitoring of Federal/ Provincial/Municipal policy across all sectors, including buildings, industry, transportation, and electricity generation and policies supporting energy efficiency, electrification, low carbon fuels and CCUS.

- As provided at Exhibit 1, Tab 10, Schedule 6, paragraph 106, Enbridge Gas will seek to understand how the Ontario government's Energy Transition and Electrification panel work will inform the Ontario government's energy transition policy and consequently the long-term viability of Enbridge Gas's assets. The Company has highlighted to the panel, the resiliency, reliability and future value of Ontario's 150,000 kms of underground gas storage, transmission and distribution assets in relation to the future cost of providing equivalent resiliency and reliability from a largely above ground electric transmission and distribution system. Enbridge Gas supports the panel's focus on integrating gas and electricity system planning and believes in the prudence of programs like the Ontario government's Clean Home Heating program that offers incentives for installation of heat pumps with smart controls in gas heated homes.

b) Yes. It is Enbridge Gas's view that the company should fully recover the costs of prudently invested capital. As provided in response at Exhibit I.1.10-SEC-28, Enbridge Gas has shown that in 2021, $16 billion of invested capital in the gas storage, transmission and distribution system delivers over four times the peak capacity delivered by the $25 billion invested in the electricity distribution system. The *current* unit cost of invested capital to deliver peak capacity in the form of natural gas is a quarter of that for electricity. Also, the underground gas system is more resilient than the largely above ground electricity system in Ontario.

Enbridge Gas has invested shareholder capital to serve its customers under a regulatory compact that allows the Company to earn a fair rate of return and for the recovery of prudently invested capital through the rates charged to its customers. Enbridge Gas expects its underground storage, transmission and distribution assets to be used or useful for the foreseeable future due to their current capacity to deliver vast amounts of energy annually and on a peak basis, inherent resiliency and the low cost of connecting to the gas system.

Enbridge Gas expects to fully recover from its customers the cost of prudently invested long-lived capital and operating and maintenance costs of providing safe, reliable and affordable energy to them. Increasing the fixed charges to connect to the system as proposed in this Application will provide cost recovery even if the amount of natural gas consumed is gradually displaced by non-emitting electricity.

Should the government institute a policy mandating disconnection from the gas system, the Company expects that it will accelerate recovery of its invested capital through regulatory measures such as higher depreciation rates and other tools including cost allocation changes to reflect a changing customer mix over time.

c) Enbridge Gas's perspective is that the increase in equity thickness mitigates the risk of investors attributing higher risk premiums with consequential impacts on the Company's cost of capital and more significant impact on customer rates.

d) Enbridge Gas is currently not experiencing a trend towards customers leaving the system nor does it have information suggesting that existing customers intend to leave the system. As noted above, Enbridge Gas is supportive of hybrid heating technologies which can reduce customers' annual GHG emissions by pairing non-emitting electricity with natural gas use to meet peak heating demands. Enbridge Gas's proposed connections policies, including the free service allowance for in-fills are established in such a manner as to ensure compliance with E.B.O 188 and the underlying principle that new customer revenues are sufficient to support their costs and do not impact the rates of existing customers. In addition, feasibility parameters such as the revenue horizon are set out in E.B.O 188 Section 2.2 Specific Parameters.

TAB 2

> Project,[116] respectively. Intervenors have challenged those projects, in part, on concerns about long-lived assets becoming stranded because of the declining use of fossil fuels, including natural gas.[117]

The above-referenced leave to construct applications are individual data points and do not represent a comprehensive review of all of the Company's filings since 2012. However, they do serve as case studies illustrating that the Company's experience is consistent with the broader natural gas industry. Thus, we conclude that the Energy Transition has significantly increased the Company's operational risk by increasing the possibility that it will face challenges and delays in siting, permitting, and constructing facilities.

c) Stranded Asset Risk

Another risk of the Energy Transition is that a significant portion of the Company's gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as the Company generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. In fact, the OEB recently acknowledged the risk of stranded assets when evaluating the Company's IRP proposal.[118]

The potential for stranded assets was not a material concern for the Company in 2012 (i.e., the time of its previous equity thickness proceedings). As S&P notes, "[s]tranded costs have not up until now been an issue for gas local distribution companies."[119] S&P observes, however, that concerns about stranded assets have spiked recently:

> *While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects*

116 EB-2022-0157.

117 See, e.g., EB-2022-0088, Pollution Probe Submission, September 23, 2022, at 4; and Environmental Defence Submission, at 2-3. See also, e.g., EB-2022-0157, Interrogatories of Environmental Defence (September 1, 2022), at 4-6.

118 EB-2020-0091, Decision and Order, July 22, 2021, at 62.

119 S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

> *has declined in recent years, the specter of stranded assets did not really emerge for existing gas pipelines and the gas LDCs until recently when the zero-carbon movement picked up steam.*[120]

S&P concludes that "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond." [121]

Investors are acutely aware of the increase in stranded asset risk and expect utilities to work with their regulators to mitigate this risk. For example, as Moody's notes:

> *Supportive regulation likely to help companies avoid stranded asset risk. State regulators and utilities will likely collaborate to avoid stranded asset risk as exposure to such risks increases. Adjusting the useful life of assets, accelerating depreciation rates of existing assets and securitizing the asset value of at-risk property, plant and equipment help ensure full investment recovery and support long term utility credit quality.*[122]

Like Moody's, Concentric expects that the OEB will approve measures to mitigate the Company's stranded asset risk, up to and potentially including the acceleration of depreciation rates as appropriate. However, we note that this is a "downside-only" area for the Company. In other words, while regulatory changes (e.g., the acceleration of depreciation rates) may improve the Company's prospects of recovering its investment, there remains a chance that investors are not able to earn a full "return of" their invested capital. There is no scenario under which investors face less risk than before the advent of the Energy Transition. Further, all else equal, accelerating depreciation rates will increase rate pressure for customers, rendering natural gas less competitive against alternative energy sources, mainly electricity. Therefore, while we expect the OEB and the Company will work together to mitigate stranded asset risks, we conclude that stranded asset risks have increased since 2012.

d) Going Concern

Depending on the specific pathways ultimately taken by the Canadian federal government and the province of Ontario, the Company may no longer be able to engage in the provision of its main business enterprise: the distribution of natural gas.

120 *Ibid*.
121 *Id*., at 11.
122 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

TAB 3

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 1, Tab 10, Schedule 6, pp. 13-14

Question(s):

Enbridge Gas describes the objectives of its Energy Transition Plan and also describes how it considers an action to be a 'safe bet' action.

Please describe whether and how Enbridge Gas considered the risk of asset stranding in its objectives for its Energy Transition Plan and also describe how Enbridge Gas considered the risk of asset stranding in considering whether an action is a 'safe bet'.

Response:

The risk of asset stranding was considered in Enbridge Gas's Energy Transition Plan (ETP) objectives (Exhibit 1, Tab 10, Schedule 6, p.13), in that Enbridge Gas believes achievement of the objectives will minimize this risk.

In achieving the first ETP objective, "maintaining alignment with Ontario's energy objectives and with provincial and federal energy transition and climate change targets and policies", Enbridge Gas will minimize the risk of asset stranding. Both federal and provincial governments, through policies and discussion papers, show support for a diverse set of actions that rely on the continued use of the gas system. These diverse actions include support for energy efficiency, electrification, low-carbon fuels, and carbon capture, utilization, and sequestration (CCUS) (Exhibit 1, Tab 10, Schedule 6, p. 9).

By achieving the second ETP objective, "providing cost-effective, secure, reliable and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved", Enbridge Gas believes its assets will remain of value and, therefore, the risk of asset stranding is minimized. It is for this reason that Enbridge Gas commissioned a study that sought to understand how net-zero goals could impact natural gas demand and what role the gas system could play in Ontario in achieving its GHG reduction targets, please see Exhibit 1, Tab 10, Schedule 5 for the study's details). The Pathways to Net-Zero Emissions for Ontario (P2NZ) Study found that both

the Electrification and Diversified scenarios achieve net-zero GHG emissions by 2050, that a diversified scenario achieves significant savings as compared to an electrification scenario and that regardless of the pathway chosen to achieve net-zero, energy efficiency, RNG, hydrogen and natural gas with CCUS are required.

By achieving the third ETP objective, “supporting an orderly energy transition in Ontario”, Enbridge Gas believes that customer choice will be maximized and that no one group of customers will carry the burden of reaching net-zero. Enbridge Gas believes that achievement of this objective will require the use of the Company’s assets and, therefore, achieving this objective will mitigate the risk of asset stranding.

Finally, Enbridge Gas’s definition of a safe bet action was created with the risk of asset stranding at the forefront. It is for that reason that each proposed safe bet action not only fulfills the safe bet definition, but it also does not result in overinvesting in a particular pathway prior to the Ontario government defining its energy transition plans in more detail.

TAB 4

32. The above has been used to inform Enbridge Gas's vision of Ontario's energy sector, provided at Exhibit 1, Tab 10, Schedule 5, Section 3, Enbridge Gas's ETP and its related proposals, which are provided in Section 2, and has been considered in the Company's forecasting and planning, as provided at Exhibit 1, Tab 10, Schedule 4, Sections 1 and 2.

2. Enbridge Gas's Energy Transition Plan (ETP) to Reduce GHG Emissions

33. Enbridge Gas has developed an ETP, including some "safe bet" actions and proposals, to recognize and incorporate, where possible, the current impacts of energy transition and to ensure that progress towards Ontario's 2030 GHG emissions reduction targets and a net-zero future can continue despite the current pathway uncertainty.

34. The objectives of Enbridge Gas's ETP are to:

a) Support an orderly energy transition in Ontario;
b) Provide cost-effective, secure, reliable, and resilient energy for customers during the transition to a low-carbon economy and once net-zero is achieved; and
c) Maintain alignment with Ontario's energy objectives and with provincial and federal energy transition and climate change targets and policies.

35. Enbridge Gas believes in its vision of a diversified pathway for Ontario, as provided at Exhibit 1, Tab 10, Schedule 5, Section 3; however, it also acknowledges that there are alternate views and, as noted above, that GHG reduction targets and supporting policies have not yet been developed in Ontario beyond 2030. As a result, uncertainty exists with regards to what path will unfold and at what pace, including which policies and investments will be made and when. While the

government and stakeholders work to determine how best to achieve net-zero, Enbridge Gas believes that if energy transition is to be implemented in an orderly manner, that delaying all action is not an option. Despite the uncertainty that exists, there are safe bet actions that can and need to be taken now.

36. Enbridge Gas considers an action to be a safe bet if it:
    a) Supports Ontario's near term GHG reductions, including achievement of the 2030 target; and/or
    a) Is required, regardless of whether a diversified or an electrification pathway unfolds in Ontario; and/or
    b) Maintains consumer choice, a safe and reliable gas system in a manner that considers pathway uncertainty, and/or pathway optionality until greater certainty around how best to transition is obtained.

37. The safe bet actions that have shaped Enbridge Gas's ETP are:
    a) Maximizing energy efficiency;
    b) Increasing the amount of RNG in the gas supply;
    c) Reducing GHG emissions from the industrial and transportation sectors via fuel switching and CCUS;
    d) Integrating gas and electric system planning; and
    e) Supporting consumer choice and the energy transition journey.

38. With the ETP based upon these identified safe bets and objectives, Enbridge Gas believes the ETP, and its associated rebasing application proposals, are prudent as they support continued progress towards a net-zero future despite current policy uncertainty, but they don't overinvest in a particular pathway prior to the Ontario government defining its future energy transition plans in more detail.

39. Enbridge Gas's ETP includes actions ranging from those which Enbridge Gas has been undertaking for some time, such as Demand Side Management (DSM), to actions that the Company is in the early stages of exploring, such as CCUS. Enbridge Gas notes that not all actions discussed within its ETP have associated proposals within the rebasing application. In some cases, where noted, the safe bet action requires additional provincial government policies, investments, and/or OEB support to move forward. A discussion of all actions Enbridge Gas is exploring, or pursuing has been included to provide the OEB with a full picture of the role Enbridge Gas can play in supporting Ontario's energy transition, both during the rebasing term and over the longer term. Enbridge Gas may bring forward applications in the future to implement additional actions contemplated in its ETP or in future iterations.

40. Table 1 identifies, for each safe bet, the ETP rebasing proposal, where applicable. Following Table 1 is a more detailed overview of each safe bet and the associated actions that Enbridge Gas is proposing, pursuing, or exploring.

Table 1
Summary of Energy Transition Related Rebasing Proposals

Safe Bet	Enbridge Initiative	Rebasing Proposal	Proposal Related Evidence
Maximizing Energy Efficiency	DSM	• No proposal. • The DSM Plan for 2023-2027 is currently pending OEB approval through a separate application[31]	Not applicable

[31] EB-2021-0002

Investing in Renewable Natural Gas (RNG)	Voluntary RNG Program	Proposal: • Discontinue the current pilot Voluntary RNG (VRNG) program and establish a Low-Carbon Voluntary Program (LCVP) for large volume sales service customers. • Procure up to 1% of the planned gas supply commodity purchases as low-carbon energy beginning in 2025 and increasing by 1% annually up to 4% in 2028. • Include any costs not recovered through the LCVP in the cost of gas supply commodity purchases.	Exhibit 4, Tab 2, Schedule 7
	RNG upgrading	• No proposal. • Note: Enbridge Gas's Asset Management Plan (AMP) includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
Decarbonizing the Industrial and Transportation Sectors	Industrial fuel switching	• No proposal. • Note: Enbridge Gas's AMP includes strategies to support investments for RNG injection stations.	Exhibit 2, Tab 6, Schedule 2
	Carbon Capture and Sequestration (CCS)	• No proposal.	Not applicable

TAB 5

3.1.1 Enbridge Strategic Priorities

The Enbridge Strategic Priorities (see **Section 2.2.2**) enable the Company to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support Enbridge's purpose of fueling people's quality of life, while maintaining the foundation of the business, positioning the organization for the future and supporting EGI's ambition to be the utility and sustainable energy provider of choice.

The Asset Management Policy translates Enbridge's strategic priorities into a series of policy statements that guide all aspects of the asset management system.

3.1.2 Asset Management Policy

Vision and Mandate

Enbridge exists to fuel people's quality of life with a long-term vision to be the leading energy delivery company in North America. Enbridge Gas Inc. (EGI) is committed to the safe, reliable, cost-effective and environmentally responsible provision of energy to its customers. At the core of this commitment is the effective stewardship of EGI's assets through governance, policy, and practices. EGI will apply leading asset management practices to effectively manage the life cycle of assets as EGI supports the transition to a low-carbon future. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances cost, risk and performance.

Scope

The Asset Management Program considers all EGI assets, inclusive of commodity-carrying assets directly related to the task of transporting natural gas and low-carbon energies from the source to the end-use customer, as well as assets that support business operations. The asset classes are Distribution Pipe, Distribution Stations, Utilization, Growth, Compression Stations, Liquified Natural Gas, Transmission Pipe and Underground Storage, Fleet and Equipment, Real Estate and Workplace Services, and Technology and Information Services. At this time, the Asset Management Program does not consider EGI's affiliates. The Asset Management Program is a component of EGI's Integrated Management System which provides a systematic approach to managing safety and reliability across the organization.

Asset Management Program

Asset Management goals include employee and public safety, compliance, value to stakeholders and financial performance. EGI's value-based decision-making incorporates environmental sustainability, and the transition of customers' needs to low-carbon energy solutions. EGI employees must consider these goals when evaluating costs, risks, and performance related to asset investment decisions over the whole asset life cycle. Decisions are made through documented and transparent evaluation processes including recent additions related to the IRP Framework (EB-2020-0091).

EGI leverages an Asset Management Program based on the industry standard, Global Forum on Maintenance & Asset Management (GFMAM), to demonstrate a systematic and coordinated approach to asset management activities. Consistent practices, processes and tools are used to manage assets optimally and sustainably. This is be achieved by balancing cost, risk, and performance throughout the asset's life cycle while providing value to customers and stakeholders.

Policy Statements

1. EGI continuously improves and aligns its asset management approach across all asset classes within EGI, by driving innovation in the development of people, tools, processes, and solutions.
2. EGI is committed to prudent value-based decision-making that incorporates energy transition for all asset-related investments on a holistic evaluation of cost, risk, and performance.
3. EGI is committed to sustainable/lower-carbon initiatives, including IRP, and new energy solutions, as well as the incorporation of these strategies within Asset Management planning and investment decisions.
4. EGI is committed to a continual, comprehensive condition assessment and risk review. EGI acknowledges that the understanding of the asset's life cycle is critical for decision-making and the safe and reliable delivery of energy.
5. EGI acknowledges that asset information is critical to transparent knowledge-based decision-making. EGI ensures that its processes, systems and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate and accessible asset information.
6. EGI is committed to meeting or exceeding compliance with all applicable laws and regulations, industry codes, standards and internal policies.
7. EGI is committed to understanding and delivering value to its customers and stakeholders.
8. EGI uses this policy and EGI's Asset Management Program to guide asset investments, as endorsed by Senior

Leadership, over the life cycle of each asset class.

3.2 EGI Integration and Continual Improvement

This document reflects the integrated utility's Asset Management Plan for the next 10 years, with assets for the rate zones (the EGD and the Union North and South rate zones) being maintained separately for capital planning purposes in 2023 and as EGI from 2024 through to the end of 2032.

EGI continues to evolve its asset management practices to produce a comprehensive Asset Management Plan. As a result, the following changes were implemented:

- **Energy Transition**
  This AMP incorporates assumptions for customer additions, peak hour demand and peak day demand, each of which have been adjusted to reflect EGI's current view of the impacts of the Energy Transition (see Exhibit 1, Tab 10, Schedule 4). EGI acknowledges that energy transition is evolving and that investment decisions will be based on the best information at the time, including consideration of IESO's forecast electricity demand. EGI maintains its obligation to serve and is committed to implementing IRP with the intent of evaluating and comparing both supply-side and demand-side options to meet an energy system need in the immediate, medium and longer term.

- **Integrated Resource Planning (IRP)**

  IRP represents a significant change to the facility planning that EGI has performed in the past and, as such, EGI is taking steps to develop processes, resources and capabilities to integrate new IRP requirements into its existing asset management process and other processes. EGI's AIPM process now incorporates the IRP assessment process. The IRP assessment step of the AIPM process (see **Section 4.3.4.1**), determines if an IRPA evaluation is required for each system need, and, if so, a cost-effective IRPA exists. Further details on the IRP assessment process can be found in EGI's IRP Annual Report.

  Through the IRP assessment process, EGI has performed IRP Binary Screenings on eligible projects, consistent with the guidance provided by the OEB in its Decision. The IRP Binary Screening results and the associated IRPA evaluation statuses, by project, can be found in **Appendix B – IRP**.

- **Alignment with Enbridge Inc.'s 2022 Enbridge Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2022. The alignment of EGI's Asset Management Policy, Asset Management Strategies and dimensions of risk have been reviewed to confirm alignment and are found in **Section 4**.

- **Organizational structure changes to align roles and responsibilities within the integrated utility**

  The phase two Boundary and Real Estate initiative has been completed. EGI's regional boundaries and real estate assets across the province were reviewed to align current boundaries and strategically locate EGI's operating depots. The second phase of the initiative evaluated the area between the GTA West and Southeast regions. In January 2022, the regional borders were realigned to optimize the facilities within each new region.

- **Consolidation of asset data**

  The systems of record for asset data in the Union rate zones include Maximo for meter, work, damage and condition data; SAP-PM for station work and asset data; GIS for pipe data; and CORR for corrosion data. Some data that supports the Asset Management Plan is now being migrated to a datamart as part of the integration of work and asset management systems. Ongoing documentation and consolidation of these datasets will enable EGI to analyze inventories more efficiently for the combined utility and better support the Integrity and Asset Management functions.

- **Evolution of asset condition and strategies**

  Section 5, which addresses asset inventory, condition, risk/opportunity and strategy outcomes, has been updated to reflect the current understanding of assets. Specific project and program information is provided in **Section 6** to support each asset class's strategic plans. Key changes are:

  - Review, comparison and integration where feasible of asset strategies, asset classes, asset condition, inventories, programs and processes between the two legacy companies
  - Mapping the capital expenditures presented in **Section 5** to the asset class strategy
  - Identification of outstanding items that remain in legacy programs until they can be integrated

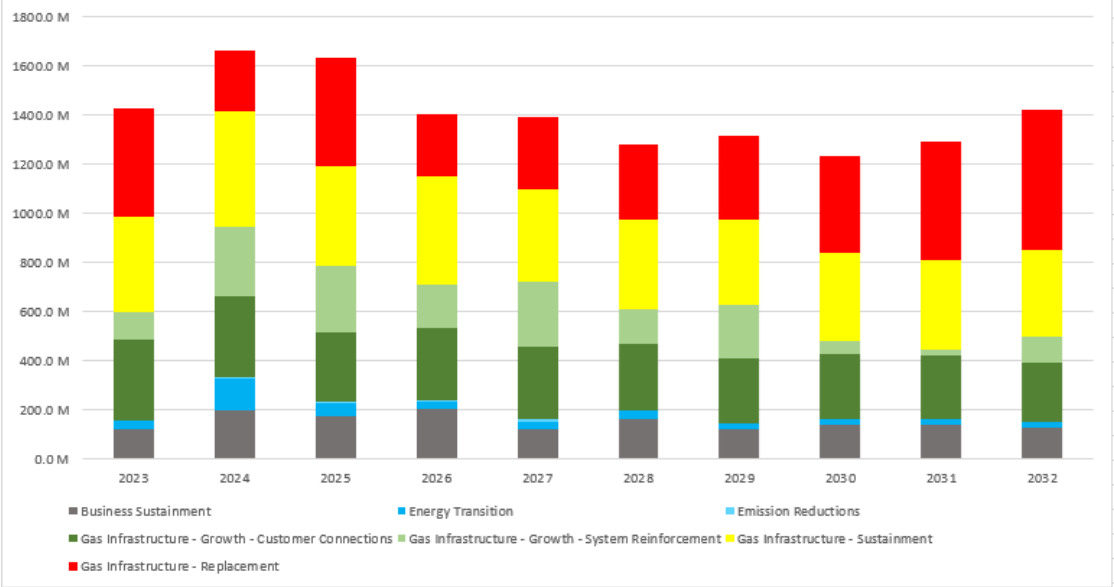
- **Integration items to highlight**

  Standards for installation, inspection, operation, maintenance, and asset decommissioning continue to be integrated. This work is ongoing; some legacy practices continue to be followed for each rate zone as analysis deemed it as appropriate for the assets at this time. Other design changes may be implemented on a go-forward basis. These new

TAB 6

	life or maintain the current function of existing assets. Also included in this category are investments necessary to maintain compliance or address known safety/reliability risks that cannot otherwise be mitigated. Examples include integrity programs; compliance programs; relocation programs; component replacements and overhauls for stations, LNG, compressor and storage assets (required based on performance degradation, failures, risk, condition or obsolescence); pipeline replacements to address inoperable valves, and small distribution station replacements to address risks that cannot be addressed through component replacements.
Growth	**Gas Infrastructure – Growth – Customer Connections**: This investment category includes all costs associated with connecting new customers to Enbridge Gas's distribution, transmission and storage system, including costs for meters associated with new customer attachments. Community Expansion is included in this investment category.
	Gas Infrastructure – Growth – System Reinforcement: This investment category is required to maintain minimum system pressures so that demand for gas can be met during design day conditions.
Business Sustainment	**Business Sustainment**: This investment category is comprised of TIS, REWS and fleet investments including CNG station replacements/builds for Enbridge Gas's fleet.
Emission Reductions	**Emission Reductions**: This investment category relates to expenditures to reduce emissions, other than those emission reductions required for compliance reasons.
Energy Transition	**Energy Transition**: This investment category relates to increasing the use of hydrogen and RNG/CNG.

Figure 2: Capital Expenditures – 2023 to 2032 /u



Notes:

1) See footnote 6.
2) The Dawn to Corunna Project represents $292.2 million and $13.8 million of Gas Infrastructure – Replacement in 2023 and 2024, respectively.

24. The capital expenditure profile over the next incentive rate mechanism term (2025 to 2028) is focused on meeting current customer demands and addressing system reliability until such time that more definitive policies relating to energy transition are established by the Ontario and municipal governments. As Figure 2 shows, the majority of Enbridge Gas's capital expenditures are required for gas infrastructure sustainment and replacement. Approximately 65% of the capital expenditures from 2023 to 2032 are related to sustainment and replacement, of which 84% is required for gas infrastructure. Further, approximately 68% of the replacement related investments in the 2024-2028 forecast would be considered short term or reactive as described in Table 1 above. These categories address risk(s) that are expected to be realized within one to twenty years, however the specific timing of those risks /u

cannot be identified with certainty. In other words, the majority of capital requirements for the foreseeable future are required for maintaining gas infrastructure, not expansion of gas infrastructure.

25. While the gas system is expected to continue playing a critical role in meeting Ontario's energy needs over the 2023-2032 period, growth related investments in this same timeframe begin to decline. This decline in the growth investment category reflects the expectation that although demand for gas remains strong in the near-term, over time fewer customers are forecasted to attach to the gas system and those customers using gas will use less. The growth capital included within the 2023-2032 plan reflects the investments required to fulfill known and forecasted customer requests for access to the gas system and to the affordable, reliable and resilient source of energy it provides. Enbridge Gas believes that these growth-related investments can be transitioned to deliver low and zero carbon energy, and that these investments maintain consumer choice and economic competitiveness, two critical elements of the energy transition. /u

26. Approximately 32% of capital expenditures relate to growth investments from 2023 to 2032. The growth investment category is largely comprised of investments related to Customer Connections, at 20% of the total 2023 to 2032 forecast, with some larger investments to support major transmission reinforcements comprising approximately 8% of the total AMP forecast. All reinforcements will be subject to IRP evaluations to seek opportunities to reduce, defer or delay scope associated with these investments. /u

27. Table 2 sets out the numerical information underpinning Figure 2. /u

Table 2: Capital Expenditures – 2023 to 2032 /u

Investment Sub-Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gas Infrastructure - Replacement - Reactive	51.2 M	60.7 M	40.6 M	44.1 M	56.6 M	72.4 M	58.3 M	61.4 M	76.7 M	58.9 M
Gas Infrastructure - Replacement - Proactive - Short Term (1y +)	353.9 M	147.5 M	283.7 M	126.1 M	153.5 M	60.6 M	60.9 M	63.0 M	66.6 M	62.5 M
Gas Infrastructure - Replacement - Proactive - Long Term (20y +)	1.9 M	1.4 M	0.9 M	11.8 M	18.5 M	94.0 M	146.6 M	208.7 M	270.7 M	320.5 M
Gas Infrastructure - Replacement - Proactive - Long Term Cost Effectiveness*	34.0 M	39.7 M	113.5 M	75.4 M	64.6 M	75.3 M	74.1 M	64.0 M	69.5 M	124.5 M
Gas Infrastructure - Sustainment	391.8 M	472.7 M	406.6 M	439.0 M	378.6 M	367.7 M	345.8 M	359.1 M	361.9 M	357.3 M
Gas Infrastructure - Growth - Customer Connection	325.0 M	333.6 M	285.9 M	296.7 M	294.8 M	269.6 M	261.3 M	261.6 M	254.5 M	243.0 M
Gas Infrastructure - Growth - System Reinforcemer	112.8 M	277.4 M	268.9 M	176.9 M	262.8 M	140.9 M	220.8 M	51.8 M	27.3 M	103.0 M
Business Sustainment	119.9 M	195.8 M	171.6 M	204.1 M	122.9 M	163.2 M	121.6 M	139.5 M	139.3 M	125.1 M
Emission Reductions	0.8 M	1.8 M	4.1 M	1.2 M	11.9 M	0.0 M	0.0 M	0.0 M	0.0 M	0.0 M
Energy Transition	38.4 M	134.1 M	55.0 M	31.5 M	28.0 M	35.7 M	25.0 M	25.0 M	25.0 M	25.0 M
Grand Total	**1429.9 M**	**1665.2 M**	**1630.5 M**	**1406.7 M**	**1392.3 M**	**1279.5 M**	**1314.5 M**	**1234.1 M**	**1291.5 M**	**1419.7 M**

4. Summary

28. Enbridge Gas has prioritized its capital expenditures over the 2013 to 2024 period in order to ensure the safety and reliability of the natural gas distribution system while supporting system growth. Enbridge Gas continues to follow established budget processes to prioritize capital expenditures and accommodate the majority of capital projects within approved base rates. Enbridge Gas provided a Capital Update provided at Exhibit 2, Tab 5, Schedule 4, on June 16, 2023, to address emerging cost pressures and evolving business requirements for 2023 and 2024 and has reprioritized projects accordingly to remain within the proposed constraints for capital expenditures. The evidence provided at Exhibit 2, Tab 5, Schedule 2 further describes the prioritized spend for the 2024 Test Year. The evidence provided at Exhibit 2, Tab 5, Schedule 3 summarizes the historical capital expenditures for EGD and Union under their individual IR terms and details the year-over-year capital expenditure variances for Enbridge Gas during the deferred rebasing term. /u

TAB 7

10. As shown in Table 1, the forecasted expenditure for the 2024 Test Year is $1,470.3 million. These expenditures represent the needs identified and prioritized in the AMP, as updated through the Capital Update to ensure the safety and reliability of the Enbridge Gas system. This includes expenditures for supporting the demand for customer and system growth, maintaining pipeline integrity of the distribution and transmission systems, ensuring compliance with regulations, investing in Enbridge Gas facilities and expenditures related to system changes as a result of implementing rebasing proposals and technology investments to ensure continued reliability and security. Enbridge Gas is also committed to investing in energy transition, including low-carbon strategies to reduce greenhouse gas emissions and renewable energy opportunities to "green the grid". Information on Enbridge Gas's Energy Transition Plan is provided at Exhibit 1, Tab 10, Schedule 6. /u

11. The following sub-sections provide a discussion of the capital expenditure budget by asset class.

1.1. Growth Projects

12. The budget for Growth includes Customer Connections, System Reinforcements including Hydrogen Blending (Phase 2 of the Low Carbon Energy Project) and Community Expansion. The 2024 capital budget includes expenditures of $400.5 million for Growth Projects. Section 5.1.3 of the AMP provided at Exhibit 2, Tab 6, Schedule 2, page 64, outlines the Growth Strategy Overview for Enbridge Gas. /u

13. Customer Growth continues to drive capital requirements with approximately 40,000 customers forecast to be added in 2024. Enbridge Gas recognizes that future legislation and concerns regarding the environment and climate change may lead to changes in customer behaviour(s) and the use of natural gas over time. The long-range forecast that underpins the Customer Connection forecast in the AMP

shows a gradual decline in the annual number of customer attachments over the 10-year planning period. Exhibit I.2.6-ED-94 outline the 10-year customer additions forecast for Enbridge Gas and the energy transition forecasting assumptions for customer additions is provided at Exhibit 1, Tab 10, Schedule 4. The reduction to capital requirements resulting from energy transition forecasting are minimal and not currently reflected in the 2024 Test Year budget. However, energy transition impacts are expected to become more significant in subsequent years. The resultant change to capital requirements for customer connections will be re-assessed and reflected in future budgets and forecasts. /u

14. Enbridge Gas is proposing to harmonize the customer connection policy effective January 1, 2024. Details on the harmonized customer connection policy are provided at Exhibit 1, Tab 15, Schedule 1, Attachment 1. The budget for the years 2025 through 2032 is derived based on a portfolio approach to ensure that feasibility guidelines are met as set out in E.B.O. 188. The methodology is further described in Section 5.1.4 of the AMP, provided at Exhibit 2, Tab 6, Schedule 2 pages 64-68. The 2024 Test Year capital expenditure for Customer Connections is $304.1 million. This forecast was derived based upon the updated customer connection forecast for 2024 and estimated costs for customer connections given the connection policy proposed in Exhibit 1, Tab 15, Schedule 1, Attachment 1. /u

15. Community Expansion projects install gas distribution assets in communities that have not previously had access to natural gas. In June 2021, the Government of Ontario announced funding for community expansion and economic development projects under phase 2 of the Natural Gas Expansion Program (NGEP). Enbridge Gas was awarded $214 million to support the development of 25 phase 2 communities and 2 economic development projects with total estimated capital of $335 million (net investment of $121 million). The budget includes Community /u

TAB 8

5.1.3 Growth Strategy Overview

Table 5.1.3-1: Growth and Hydrogen Condition and Strategy Overview

Asset Program	Growth Forecast	Risk / Opportunity	Strategy
Customer Connections	**Figure 5.1-2** and **Figure 5.1-3** show the customer growth forecast for the EGD and Union rate zones respectively.	EGI is expected to provide new or upgraded natural gas services to residential and commercial/industrial customers (*EBO 188*), where the project is feasible, determined by quantifying the value of a project's revenues against its costs (the Profitability Index [PI]).	The strategy for Customer Connections is to continue to ensure required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines, while following harmonized forecasting practices. EGI continues to monitor and update the customer additions forecast through the annual long-range planning process, which considers the impact of energy transition. Economic feasibility for growth is based on *EBO 188* guidelines applied to the investment portfolio and rolling project portfolio.
Distribution System Reinforcement	To identify purpose, need and timing of distribution system reinforcements, EGI utilizes peak hourly consumption to determine distribution system needs.	Ensure security of distribution system capacity to meet the needs of existing customers and support forecasted customer growth using *EBO 188* guidelines, and in accordance with the IRP Framework.	All reinforcement projects will be subject to a Binary Screening through the IRP assessment process. IRP, as prescribed by the OEB, will allow for non-pipe alternatives to be thoroughly examined, reviewed, and implemented where economically and technically feasible. The strategy for the Distribution System Reinforcements is to continue to ensure the installation of infrastructure required to enable the addition of all forecasted customers feasible under *EBO 188* guidelines, for those that do not pass IRP screening or where IRPAs are not feasible, while following current forecasting practices, which considers the impact of energy transition.
Community Expansion	Through Phase Two of the Natural Gas Expansion Program, EGI was awarded ~$214M to support 27 Phase 2 Natural Gas Expansion Projects (NGEP) projects.	Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced by EGI.	EGI's Community Expansion Strategy is to continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. Application opportunities for project funding are dictated by the government under *Bill 32: Access to Natural Gas Act, 2018.*
Transmission System Reinforcement	To identify purpose, need and timing of transmission system reinforcements, EGI annually completes a design day demand forecast that is used to identify short- and long-range plans through model simulation.	Ensure safe and reliable transmission system operations and support increasing in-franchise and ex-franchise demand growth using *EBO 134* guidelines, and in accordance with the IRP Framework.	All reinforcement projects will be subject to a Binary Screening through the IRP assessment process. IRP, as prescribed by the OEB, will allow for non-pipe alternatives to be thoroughly examined, reviewed, and implemented where economically and technically feasible. The strategy for the Transmission System Reinforcements is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers and distribution growth feasible under *EBO 134* guidelines, for those that do not pass IRP screening or where IRPAs are not feasible, while following current forecasting practices, which considers the impact of energy transition.
Hydrogen Blending	EGI continues to evaluate the extent that hydrogen can be used in the distribution system and company assets.	The successful operation of the pilot project requires regulations and standards for hydrogen to be harmonized by governments and regulatory agencies and for hydrogen to be cost-competitive.	EGI continues to evaluate the extent that hydrogen can be used in the distribution system and company assets. EGI will apply learnings from its Hydrogen Blending pilot projects and its hydrogen blending facility in Markham to allow it to further Canadian leadership on hydrogen development and a low-carbon future. EGI continues to collaborate with governments and partners to advance innovative energy solutions to keep energy reliable, affordable and reduce environmental impact.

TAB 9

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 2, Tab 6, Schedule 2, p.280, 284, Appendix B; Exhibit 7, Tab 1, Schedule 2, pp.6-7; EB-2020-0091 decision, July 22, 2021, p. 35

Question(s):

Enbridge Gas discusses its IRP assessment results and technical evaluation project review.

a) Please provide more details on Enbridge Gas's current procedure as to how Enbridge Gas evaluates the technical viability of potential Integrated Resource Planning Alternatives (IRPAs) to reduce peak demand to the degree required to meet the identified system need. Specifically, please describe: which investment categories Enbridge Gas considers to be driven in part or in full by peak demand (and thus not automatic failures in the technical evaluation); how Enbridge Gas determines the level of peak demand reduction required to meet a system need; how Enbridge Gas assesses the technical potential of geotargeted energy efficiency to meet a system need; how Enbridge Gas assesses the technical potential of other types of IRPAs (e.g., demand response, supply-side alternatives) to meet a system need.

b) Do the investment categories considered to be driven by peak demand for the purposes of the IRP assessment align with Enbridge Gas's cost allocation methodology (Exhibit 7), which categorizes functionalized assets and operating costs as demand, commodity, and customer? Please describe and explain the rationale for any differences – i.e., if there are assets that are categorized (in part or in full) as demand costs (capacity-related costs) for the purposes of cost allocation, but not considered to be driven by peak demand for the purposes of the IRP assessment.

c) Appendix B shows the status of IRP assessments for all system needs that are direct customer connections as "planned" but notes the concern that "EGI (Enbridge Gas) is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers." Does Enbridge Gas expect that these system needs will therefore be an automatic failure in the technical evaluation? What is Enbridge Gas's approach to receiving connection requests, regarding informing

customers of options to use energy sources other than natural gas, and how, if at all, is Enbridge Gas implementing the optional approach noted in the IRP decision that "Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas"?

Response:

a) In Enbridge Gas's technical evaluation, the investment categories Enbridge Gas considers to be driven in part or in full by design hour/day demand include projects with the asset class of "growth" or "distribution pipeline."

Enbridge Gas determines the level of design hour/day demand reduction required to meet a system need by calculating:

- Total customer design hour/day demand for natural gas based on existing customer design demands plus forecasted customer growth in design hour/day minus projected reductions in the system design hour/day.

- Total current design hour/day capacity that can be provided by the existing natural gas infrastructure within the project area.

The difference between these two factors determines the design hour/day demand capacity required to meet the system needs.

Enbridge Gas assesses the technical potential of IRPAs to meet a system need as follows:

- Enhanced targeted energy efficiency (ETEE)'s technical potential is assessed by comparing the required design hour/day demand reduction to the achievable design hour/day demand reduction potential in the project's area of impact. The achievable potential is calculated by modelling the ETEE's design hour/day impacts, which includes the estimated impact ETEE has on design hour/day as well as customer participation uptake. As learnings are gained in the IRP Pilot projects, they will be applied to the ETEE's achievable potential modelling.

- Compressed natural gas (CNG) is being assessed by choosing a potential CNG location near the system's low-pressure location and calculating injection volumes that offset the system need.

- Market-based supply side is assessed by determining the availability of higher pressures or capacity from a third-party source to impact the project scope.

Following the above noted IRPA technical evaluations, Enbridge Gas applies the following technical evaluation guidance criteria:

- CNG is intended as a bridging solution in conjunction with ETEE to meet system needs rather than a permanent solution. The exception is when CNG is used as a limited peaking service.

- All IRPAs must be operationally prudent, meaning system reliability is maintained and that bottlenecks in the system, which could restrict the ability to do maintenance, are prevented.

In addition to the technical evaluation approaches noted above for each IRPA, Enbridge Gas also reviewed each of the investment categories and determined that there were several project categories that fail the technical evaluation and, therefore, did not progress to a more detailed IRPA evaluation. The investment categories that failed and the associated reasons are as follows:

- Customer Connections

    - Please see part c) below for the rationale for failing the Customer Connections category.

- Compression Stations

    - Compression Station related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions. Please see response at Exhibit I.2.6-ED-99 for the reasons IRPAs cannot be implemented to reduce Enbridge Gas's capacity and, therefore, cannot reduce its compression and deliverability assets.

- Storage Pools & Wells

    - Storage Pools & Well related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions. Please see the response at Exhibit I.2.6-ED-99 for the reasons IRPAs cannot be implemented to reduce Enbridge Gas's capacity and therefore cannot reduce its compression and deliverability assets.

- Hydrogen Related
    - Hydrogen related projects are required, as no IRPA can replace the hydrogen feasibility assessments and hydrogen blending initiatives
- Miscellaneous – these are projects with:
    - Nominal pipe size (NPS) of 2 that cannot be further downsized as this is the smallest size of gas main used by Enbridge Gas and the pipe cannot be retired. IRP evaluation is not required as this is the smallest size gas main used by Enbridge Gas.
    - Scopes that, through the Technical Evaluation Project Review, were identified as projects that could potentially be downsized to NPS 2; however, after further review it was determined that it was not possible to downsize to a NPS 2 for segments of trunk main to maintain system resiliency and avoid the introduction of bottlenecks into the system.
    - A condition driven investment at a station, and an IRPA is not applicable as it cannot delay or materially reduce the scope of such projects.
    - A leave to construct regulatory process complete, with an OEB approval of the proposed project scope.
    - The construction phase has already started.

b) Yes, the investment categories for gas-carrying assets considered to be driven by design hour/day demand for the purposes of the IRP assessment are classified as demand-related costs in Enbridge Gas's Cost Allocation Study.

c) Enbridge Gas serves new or upgraded natural gas service requests from residential and commercial/industrial customers under E.B.O 188 on the understanding that these customers are sufficiently informed about the available energy and technology solutions and that they have chosen the alternative that best suits their needs. The capital dollars within the Customer Connections budget accounts for the costs to serve new customers, including materials and installation of distribution mains, services, and regulating equipment.

As noted when the AMP was filed in October 2022, the Customer Connection capital spend passed the binary screening. During the technical evaluation stage, Enbridge Gas conducted further analysis on the customer connection capital spend to understand the applicability of IRPAs. Enbridge Gas notes that as part of the IRP Technical Working Group (TWG), some members expressed an interest in further

understanding the IRPA applicability to the customer connection capital spend. In its technical evaluation, Enbridge Gas determined that implementing an IRPA could not reduce the size of the distribution mains, services or regulating equipment, as these cannot be downsized any further. In addition, there are no non-gas IRPAs available within the current IRP Framework that can be offered to avoid the customer connection service being requested.

In general, and for specific projects, Enbridge Gas has initiated discussions with the IESO and LDCs to discuss their integrated resource plans and whether there are any partnership opportunities for both its IRP Pilot Plans, as well as for its future non-pilot IRP plans. At this time, Enbridge Gas has been focused on assessing projects in its AMP and has not looked beyond program partnership opportunities, as it agrees with the OEB's observation in the IRP Decision EB-2020-0091, page 36, "While in the longer term, there may be an opportunity to have integrated resource planning with the optimal fuel choice between all energy sources, the OEB concludes that this would be an excessively challenging requirement during the first-generation IRP Framework."

TAB 10

94% and 82% were likely to replace their equipment with natural gas space and water heating equipment, respectively, which is similar to 2020 penetration rates (96% for space heating and 85% for water heating).[4]

19. Table 2 provides a summary of the energy transition assumptions that were used to adjust the general service forecast number of customer additions (new construction and replacements) and average number of customers (existing customers). Future customer forecasts will continue to consider government policy and market trends on an annual basis to develop adjustments specific to energy transition.

Table 2

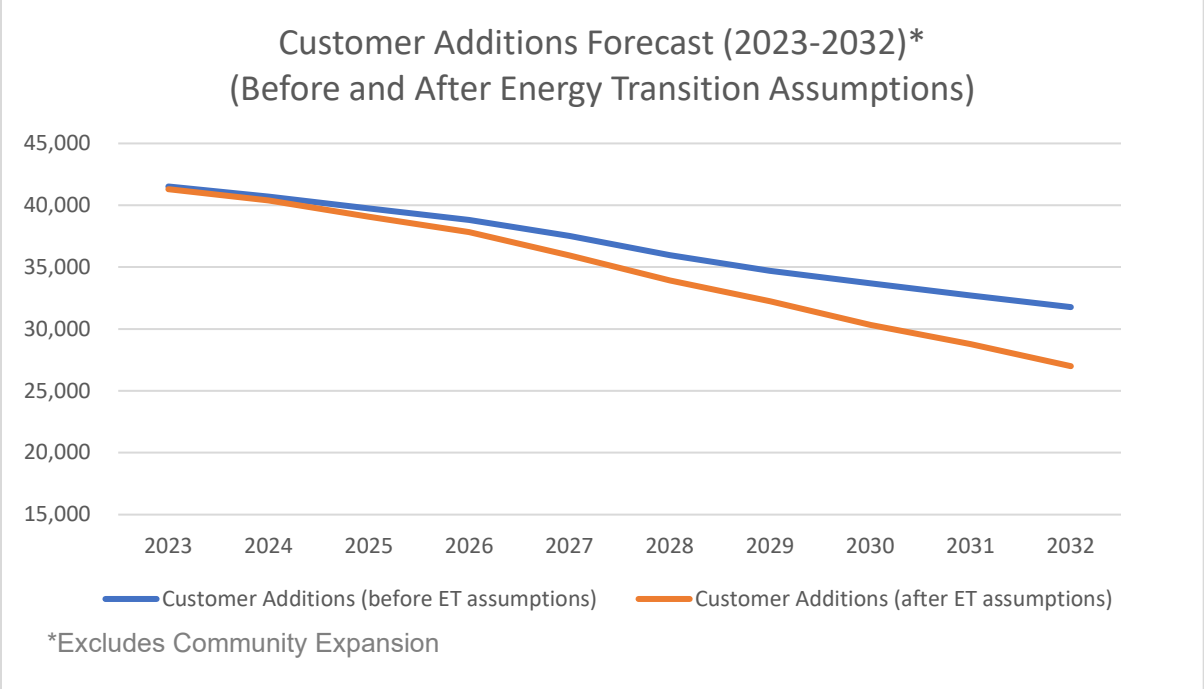
Summary of Energy Transition Assumptions Affecting Customer Forecast – General Service

Line No.	Forecast Type	Energy Transition Assumption	Forecast Item Reference
1	Customer Addition – New Construction	A small segment of builders (<1%) voluntarily do not connect to natural gas network starting in 2023, increasing to an estimated 12.5% by 2032.	- Exhibit 3, Tab 2, Schedule 6, Attachment 1, - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
2	Customer Addition – Replacement Conversions	Starting in 2030, 10% fewer existing homes (not previously heated with natural gas) convert to natural gas	- Exhibit 3, Tab 2, Schedule 6, Attachment 1 - Asset Management Plan 2023-2032, Figures 5.1.4-1, and 5.1.4-2
3	Average Number of Customers – Existing Customers	Equipment lifespan is estimated at 20 years, resulting in a 5% annual turnover rate. 10% of customers have only one gas appliance.[5] Starting in 2026, it is assumed that 10% of general service customers voluntarily replace with non-gas equipment at the end of equipment life, those with one appliance are assumed to disconnect from the natural gas network.	- Exhibit 3, Tab 2, Schedule 6, Attachment 2

[4] 2020 Residential: Single Family Natural Gas End Use Study.
[5] Based on 2019 and 2020 Residential Natural Gas End Use Survey.

20. The impact of the energy transition assumptions included in Table 2 on the total number of customers for 2024 Test Year results in approximately 321 fewer general service customers than previously forecasted. Figure 1 shows the impact of the energy transition assumptions on the customer additions forecast.

Figure 1: Impact of Energy Transition Assumptions on the General Service Customer Additions Forecast



Energy Transition Assumptions in the Volume Forecast

21. The Annual Volume Forecast for general service customers is derived from the total number of general service customers and average use per customer forecasts, and is provided at Exhibit 3, Tab 2, Schedule 7.

22. In addition to the energy transition assumptions that have been applied to customer numbers and average use forecasts noted above, Enbridge Gas also includes an

TAB 11

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit 2, Tab 6, Schedule 2, s. 5.1.4 (Customer Connections)

Question(s):

a) Please complete the following table regarding customer connections, with three years of actuals (2020-2022) followed by the AMP forecast:

Customer Attachment Totals by #, m3, m3/d, and m3/h				
	2020	2021	…	2032
Customer connections (#)				
Estimated increase in annual demand (m3) from new customers				
Estimated increase in design day demand (m3/d) from new customers				
Estimated increase in design day/hour demand (m3/hr) from new customers				

b) Please complete the following table in three versions – one with customer numbers, one with annual demand (m3), and one with design day demand (m3/day).

Customer Attachments by Sector, Before and After Energy Transition Adjustments				
	2020	2021	…	2032
Before Energy Transition Adjustments				
Residential				
Commercial				
Industrial				
Total				
After Energy Transition Adjustments				
Residential				
Commercial				
Industrial				

Total				
Difference				
Residential				
Commercial				
Industrial				
Total				

c) Please complete the following table:

Residential Customer Attachments by Type				
	2020	2021	…	2032
Number of connections (#)				
Community expansion				
Fuel switching (excl. community expansion)				
Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				
Annual demand (m3)				
Community expansion				
Fuel switching (excl. community expansion)				
Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				
Design Day Demand (m3/day)				
Community expansion				
Fuel switching (excl. community expansion)				
Homes in residential housing development (subdivisions)				
New single-family dwellings				
Other				

Response:

The responses to parts (b) and (c) below are updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

a) Enbridge Gas's annual volume forecast is not available for the categories listed. Please see response at Exhibit I.1.10-STAFF-31, Table 1 for Enbridge Gas's annual volume (demand) forecast. Table 1 shows Enbridge Gas's estimated year-over-year increase in design day and design hour demand.

Table 1
Estimated Year-over-Year Increase in Design Day and Design Hour Demand

	Customer Connections (#)	Estimated increase in design day demand (m^3/d) from new customers	Estimated increase in design hour demand (m^3/hr) from new customers
2020	Please see response to Exhibit I.1.10-STAFF-31, Table 16	Information not available in a comparable format.	83,115
2021			77,809
2022			149,226
2023		2,565,794	66,697
2024		2,520,043	63,193
2025		3,278,441	62,211
2026		4,782,402	58,377
2027		1,745,495	54,303
2028		1,673,065	50,347
2029		1,615,341	46,770
2030		1,571,344	42,480
2031		1,498,614	38,868
2032		1,466,220	34,793

b) Table 2 includes the customer additions forecast before and after energy transition assumptions. Table 3 shows Enbridge Gas's before and after energy transition assumptions design day demand. /u

Table 2
Customer Attachments (Before and After Energy Transition)* /u

	Before Energy Transition Assumptions				After Energy Transition Assumptions			
	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2024	38,055	2,546	26	40,627	37,745	2,534	26	40,305
2025	38,173	2,406	26	40,605	37,510	2,382	26	39,918
2026	38,335	2,313	25	40,673	37,308	2,278	24	39,610
2027	38,563	2,208	24	40,795	36,841	2,154	23	39,018
2028	38,069	2,097	23	40,189	35,750	2,029	22	37,801
2029	36,749	2,007	23	38,779	33,948	1,927	21	35,896
2030	35,483	1,876	21	37,380	31,934	1,732	19	33,685
2031	33,940	1,793	21	35,754	30,224	1,649	19	31,892
2032	32,589	1,721	21	34,331	28,398	1,569	18	29,985
2033	31,350	1,652	21	33,023	27,315	1,507	18	28,840

*excludes CE

Table 3
Design Day Information for Customer Attachments and Growth

m3/d	Before Energy Transition Assumptions			After Energy Transition Assumptions			Difference		
	General Service	Contract Rate	Total	General Service	Contract Rate	Total	General Service	Contract Rate	Total
2020	Information not available in a comparable format.			Information not available. Previous forecasts did not include energy transition assumptions					
2021									
2022									
2023	1,526,510	1,262,624	2,789,134	1,303,170	1,262,624	2,565,794	-223,340	0	-223,340
2024	1,485,190	1,249,311	2,734,502	1,270,732	1,249,311	2,520,043	-214,458	0	-214,458
2025	1,397,050	2,079,000	3,476,050	1,199,441	2,079,000	3,278,441	-197,609	0	-197,609
2026	1,369,411	3,603,880	4,973,291	1,178,522	3,603,880	4,782,402	-190,889	0	-190,889
2027	1,314,596	612,000	1,926,596	1,133,495	612,000	1,745,495	-181,102	0	-181,102
2028	1,240,080	612,000	1,852,080	1,061,065	612,000	1,673,065	-179,015	0	-179,015
2029	1,174,275	612,000	1,786,275	1,003,341	612,000	1,615,341	-170,934	0	-170,934
2030	1,113,433	621,760	1,735,193	949,584	621,760	1,571,344	-163,849	0	-163,849
2031	1,060,566	607,235	1,667,801	891,379	607,235	1,498,614	-169,187	0	-169,187
2032	999,965	626,525	1,626,490	839,696	626,525	1,466,220	-160,270	0	-160,270

c) Customer attachments by type are provided in Table 4. Annual demand and design day demand information is not available for the categories listed in the question.

/u

Table 4
Customer Attachments by Type Before Energy Transition Impact

	Community Expansion (CE)	Fuel Switching Other than CE	Homes in residential developments (subdivisions)	Single family dwellings (Apartment Ensuite)	Other
2020	567	5,535	30,106	5,305	2,423
2021	428	4,953	33,268	1,741	2,420
2022	314	4,128	37,583	1,973	2,133
2023	575	3,904	33,285	1,718	2,670
2024	566	3,582	32,761	1,712	2,572
2025	1,115	3,255	33,232	1,686	2,432
2026	1,461	2,904	33,763	1,668	2,338
2027	1,657	2,681	34,238	1,644	2,232
2028	1,574	2,386	34,091	1,592	2,120
2029	1,076	2,168	33,030	1,551	2,030
2030	739	1,918	32,060	1,505	1,897
2031	679	1,674	30,812	1,454	1,814
2032	390	1,519	29,652	1,418	1,742

TAB 12

ENBRIDGE GAS INC.

Accounting Entries for
Integrated Resource Planning (IRP) Operating Costs Deferral Account
Account No. 179-318

This account records incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans also includes all enabling payments to service providers, made as part of the IRP Plans. This account will also record offsetting avoided operating costs that relate to facilities that are delayed, avoided or downsized by an IRP Plan.

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

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-318 IRP Operating Costs Deferral Account
Credit	-	Account No. 728 General Expense

To record, as a debit/(credit) in the account, incremental IRP general administrative costs, as well as incremental operating and maintenance costs (inclusive of enabling payments to service providers) and ongoing evaluation costs for approved IRP Plans.

Debit	-	Account No. 300 Operating Revenue
Credit	-	Account No.179-318 IRP Operating Costs Deferral Account

To record, as a debit/(credit) in the account, avoided operating costs that relate to facilities that are delayed, avoided or downsized by an IRP Plan.

Debit	-	Account No.179-318 IRP Operating Costs Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

ENBRIDGE GAS INC.

Accounting Entries for
Integrated Resource Planning (IRP) Capital Costs Deferral Account
Account No. 179-319

This account records the actual annual revenue requirement of project costs eligible to be capitalized for inclusion in rate base as part of approved IRP Plans (where Enbridge Gas owns and operates the IRP alternatives). This account will also record offsetting avoided revenue requirement amounts already included in rates related to facilities that are delayed, avoided or downsized by an IRP Plan.

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

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-319 IRP Capital Costs Deferral Account
Credit	-	Account No. 300 Operating Revenue

To record, as a debit/(credit) in the account, the actual annual revenue requirement of project costs eligible to be capitalized for inclusion in rate base as part of approved IRP Plans (where Enbridge Gas owns and operates the IRP alternatives).

Debit	-	Account No. 300 Operating Revenue
Credit	-	Account No.179-318 IRP Operating Costs Deferral Account

To record, as a debit/(credit) in the account, avoided revenue requirement amounts already included in rates related to facilities that are delayed, avoided or downsized by an IRP Plan.

Debit	-	Account No. 179-319 IRP Capital Costs Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit/(credit) in the account, interest expense on the opening monthly balance.

TAB 13

Appendix B – IRP

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**11794**	A60: City Centre Complex - Ottawa	**2023**	$ 578,721									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**23126**	Concord St Isolated Steel Replace with Main St PE, Ottawa	**2023**	$ 599,422									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**23190**	VPM - 310 Cathcart St Header - Aldyl A	**2031**	$ 348,702									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30334**	Ann St - Eastern - Area 60 - 1100	**2032**	$ 1,452,021									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30342**	Carling Ave - Eastern - Area 60 - 1104	**2031**	$ 1,734,079									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30343**	Centre St - Eastern - Area 60 - 1085	**2027**	$ 1,108,906									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30347**	Elm St W - Eastern - Area 60 - 1726	**2028**	$ 978,033									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30352**	George St - Eastern - Area 60 - 1088	**2027**	$ 1,462,056									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30358**	Highgate Rd - Eastern - Area 60 - 1166	**2030**	$ 1,212,189									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30376**	Othello Ave - Eastern - Area 60 - 1096	**2028**	$ 1,212,878									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**30388**	Stanley Ave - Eastern - Area 60 - 1069	**2030**	$ 1,515,708									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**102424**	Relocation Program - Area 60*	**2020**	$ 13,287,715									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**501823**	A60 1149 Shillington HDR Replacement	**2023**	$ 158,256									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**502861**	Morrison THP Replacement	**2023**	$ 305,493									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**502862**	Young St LP Replacement	**2023**	$ 1,240,657									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**734548**	VSM-HWY 7 Dufferin St Perth	**2024**	$ 1,301,690									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Dollar threshold	**734590**	Viewmount Dr Main Lowering	**2031**	$ 570,662									
Eastern	**60 - Ottawa**	Distribution Pipe	**Fail**	Emergent Safety	**4665**	Replacement Blanket - Area 60*		$ 12,572,770									
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**4671**	Anode Blanket - Area 60*	**2020**	$ 3,382,114	**Justification: The Corrosion Department conducts pipe-to-soil readings each year on EGI's steel pipelines. When a corrosion area is identified as having fallen below EGI's minimum specifications, an order for a anode installation is processed. The capital request is for 12 months.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**4767**	AMP Fitting Replacement - Area 60*		$ 68,867,529	**AMP Fittings are a below grade transition fittings. The inserted portion of copper tubing can fail due to internal corrosion. In these cases leaks develop immediately downstream of the AMP Fitting.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**8198**	LANCASTER GATE Station - Integrity Retrofit > 30% SMYS	**2026**	$ 1,856,497	**Funds to install launcher (station rebuild occurred in 2016; no provisions for launcher were included) on pipeline to allow for inline inspection are required. This will allow in-line inspection of the pipeline which is required as per the Pipeline Integrity Management Program.** **General: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent inline inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections.**	Complete	**Fail**	See investment description, IRPAs not appliable					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**8262**	VSM - Preston St - LP	**2026**	$ 3,224,565	**Vintage Steel Mains, Isolated Steel Mains** **General: Vintage Steel Replacement Program is a proactive replacement program to renew aging vintage steel pipe assets before reaching their end of life. Vintage steel mains have shown signs of declining health due to the cumulative effect of poor, manufactured coating performance; construction practices; latent third-party damages to pipe coating; and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. Vintage steel systems also have potential to include compression couplings, shallow installation depth and shallow assemblies making pipe susceptible to third-party damage, and manufactured defects associated with seam welds and fittings.**								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**10288**	St. Laurent Phase 4 - Lower Section (Plastic)	**2025**	$ 11,339,012	**Issue/Concern:** **General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures.** **In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:** **•Compression couplings** **•Shallow blow-off valve assemblies that could be damaged during excavation activities** **•Reduction in the original depth of cover** **•Continuous exposure of road salt and seasonal ground movement on bridge crossing assets** **•Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment** **•Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion** **•Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.** **Site-Specific Concerns:** **Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network. Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral**	Planned						
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**10290**	St. Laurent Phase 3 - Coventry/Cummings/St. Laurent (Plastic)	**2024**	$ 11,273,059	**General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:** **•Compression couplings** **•Shallow blow-off valve assemblies that could be damaged during excavation activities** **•Reduction in the original depth of cover** **•Continuous exposure of road salt and seasonal ground movement on bridge crossing assets** **•Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment** **•Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion** **•Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.** **Site-Specific Concerns: Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network.** **Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (and does not include the crossing at the Rideau River to Station #61171A).** **In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 km of plastic pipe was installed on**	Planned						

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**10292**	St. Laurent Phase 3 - Montreal to Rockcliffe (Plastic)	**2024**	$ 11,877,934	**General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor-manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection show an increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:** **•Compression couplings** **•Shallow blow-off valve assemblies that could be damaged during excavation activities** **•Reduction in the original depth of cover** **•Continuous exposure of road salt and seasonal ground movement on bridge crossing assets** **•Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment** **•Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion** **•Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.** **Site-Specific Concerns:** **An inability to determine leaks due to the close proximity of the NPS 12 470 psi system is a concern. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network.** **Full replacement of main comprising Network 6584 is required - the NPS 12 St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (and does not include the crossing at the Rideau River to Station #61171A).**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**10293**	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	**2024**	$ 59,372,892	**The NPS 12 St Laurent Pipeline requires replacement due to various pipeline conditions associated with the 1970 vintage steel mains including poor coating, unknown compression coupling fittings, reduced depth of cover, corrosion induced by declining cathodic protection. Replacing the main will ensure continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public. This project will install 6.5 km NPS 12 Steel Gas Main, 2.4 km NPS 16 Steel Gas Main, 5.1 km Plastic Gas Main and relay all XHP services to the new plastic gas main.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**10294**	St. Laurent Phase 4 - East/West (NPS12 Steel)	**2025**	$ 24,233,805	**The NPS 12 St Laurent Pipeline requires replacement due to various pipeline conditions associated with the 1970 vintage steel mains including poor coating, unknown compression coupling fittings, reduced depth of cover, corrosion induced by declining cathodic protection. Replacing the main will ensure continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public. This project will install 3.1 km NPS 12 Steel Gas Main, Install 3.2 km Plastic Gas Main and relay all XHP services to the new plastic gas main**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**13609**	Service Relay Blanket - Area 60*	**2020**	$ 52,687,565	**General: A distribution service refers to the pipe between the distribution main and the customer's meter set. Over the years, different materials have been used for this asset, including steel, copper, and varying resins of plastic, each with unique characteristics** **that contribute to their performance over time. Services can be repaired or replaced depending on asset condition and the nature of the issue exhibited. Generally, replacement is the preferred approach to mitigate unacceptable asset condition.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30330**	2nd Ave - Eastern - Area 60 - 1197	**2028**	$ 4,087,217	**2nd Ave. - Eastern - Area 60 - 1197** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30331**	3rd Ave - Eastern - Area 60 - 1226	**2030**	$ 3,232,112	**3rd Ave. - Eastern - Area 60 - 1226** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30332**	Adelaide St - Eastern - Area 60 - 1218	**2031**	$ 2,158,470	**Adelaide St. - Eastern - Area 60 - 1218** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30333**	Ainsley Dr - Eastern - Area 60 - 1723	**2027**	$ 2,128,900	**Ainsley Dr - Eastern - Area 60 - 1723** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Remove 8 m of mains from project due to overlap (updated as per regional feedback).**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30338**	Beckwith St N - Eastern - Area 60 - 1198	**2032**	$ 2,688,181	**Beckwith St. N. - Eastern - Area 60 - 1198** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30339**	Bell St - Eastern - Area 60 - 1052	**2032**	$ 2,274,693	**Bell St. - Eastern - Area 60 - 1052** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: No timing comment was provided.**	Complete	**Fail**	NPS 2, cannot downsize or retire				

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30340**	Borthwick Ave - Eastern - Area 60 - 1139	**2031**	$ 3,192,788	**Borthwick Ave. (moratorium is until 2025) - Eastern - Area 60 - 1139** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Road work was completed in 2020. Road restrictions will be in place for a long time. The 2025 execution date is based on region's comment.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30341**	Brock St - Eastern - Area 60 - 1485	**2032**	$ 3,472,215	**Brock St. - Eastern - Area 60 - 1485** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire						
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30345**	Drummond St W - Eastern - Area 60 - 1142	**2028**	$ 2,470,450	**Drummond St. W. - Eastern - Area 60 - 1142** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30346**	Elm St E - Eastern - Area 60 - 1147	**2032**	$ 2,426,470	**Elm St. E. - Eastern - Area 60 - 1147** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions on County Rd 29 and 15.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30348**	Elmsley St N - Eastern - Area 60 - 1725	**2032**	$ 1,861,690	**Elmsley St. N. - Eastern - Area 60 - 1725** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: A possible permit may be required due to proximity to rail yard. A possible Conservation Authority (CA) permit may be required due to historic buildings. Estimate includes 46 m of PE replacement but the number of services may not be correct;**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30349**	Emily St - Eastern - Area 60 - 1101	**2031**	$ 2,287,957	**Emily St. - Eastern - Area 60 - 1101** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30350**	First Ave - Eastern - Area 60 - 1175	**2031**	$ 3,442,055	**First Ave. - Eastern - Area 60 - 1175** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30351**	Flora St - Eastern - Area 60 - 1151	**2032**	$ 2,528,992	**Flora St - Eastern - Area 60 - 1151** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Possible road work to occur along High St.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30354**	Grant St - Eastern - Area 60 - 1098	**2032**	$ 2,665,699	**Grant St. - Eastern - Area 60 - 1098** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Possible CA permit may be required due to proximity to Tay River.**	Planned								
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30356**	Havelock St - Eastern - Area 60 - 1215	**2031**	$ 4,243,311	**Havelock St. - Eastern - Area 60 - 1215** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned								

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

Region	Operating Area (EGI)	Asset Class	Binary Screening (Pass/ Fail)	Cause of Binary Fail	Investment Code	Investment Name	In Service Date	2023-2032 Forecast (Includes overhead allocation)	Investment Description - Binary Screening - Pass	Technical Evaluation Completion Status	Technical Evaluation Results	Technical Evaluation - IRPAs Considered	Economic Evaluation Completion Status	Economic Evaluation Results	Economic Evaluation - IRPAs Considered	IRP Plan Completion Status	IRP Plan - IRPAs Considered
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30357**	Herriott St - Eastern - Area 60 - 1089	**2032**	$ 1,848,715	**Herriott St. - Eastern - Area 60 - 1089** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There are possible road restrictions on Moffatt Asphalt Overlay.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30359**	Irene Cres - Eastern - Area 60 - 1141	**2028**	$ 2,919,753	**Irene Cres. - Eastern - Area 60 - 1141** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30360**	James St - Eastern - Area 60 - 1112	**2029**	$ 2,617,144	**James St. - Eastern - Area 60 - 1112** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: CR 34 Major Rd. into Quebec might require an MTO permit. Main St. is already dual-mained and side streets could be considered. Possible CA permit may be required due to proximity to Ottawa River.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30361**	James St W - Eastern - Area 60 - 1184	**2031**	$ 2,941,172	**James St. W. - Eastern - Area 60 - 1184** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30363**	Lake Ave E - Eastern - Area 60 - 1145	**2032**	$ 4,172,549	**Lake Ave. E. - Eastern - Area 60 - 1145** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30364**	LePage Ave - Eastern - Area 60 - 1214	**2029**	$ 3,885,028	**LePage Ave. (execute by 2025 - paving proposed between 2022 - 2025) - Eastern - Area 60 - 1214** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: Some road and sewer work was done in 2021, and paving is proposed between 2022 and 2025 - updated to reflect region's comments.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30365**	Madawaska St - Eastern - Area 60 - 1072	**2030**	$ 3,169,523	**Madawaska St - Eastern - Area 60 - 1072** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30366**	Main St E - Eastern - Area 60 - 1172	**2031**	$ 3,168,096	**Main St. E. - Eastern - Area 60 - 1172** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.** **Comments: There is 83 m of 2-inch steel being replaced. Downtown road is likely to have time restrictions.**	Complete	**Fail**	NPS 2, cannot downsize or retire					
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30367**	McCann St - Eastern - Area 60 - 1160	**2029**	$ 4,429,658	**McCann St. - Eastern - Area 60 - 1160** **Vintage steel pipes exhibit increased failures as they age as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							
Eastern	**60 - Ottawa**	Distribution Pipe	**Pass**		**30368**	McGonigal St E - Eastern - Area 60 - 1041	**2032**	$ 2,640,734	**McGonigal St. E. - Eastern - Area 60 - 1041** **Vintage steel pipes exhibit increased failures as they age, as steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing and hence reaching the end of their useful life. EGI has determined that a long-term proactive replacement program targeting higher-risk steel pipes installed on or before 1970 (vintage steel) is required to manage the increasing number of expected leaks that create increasing risk for the organization.**	Planned							

* in the Investment Name indicates a program item. Program items are unique as they represent numerous projects grouped together and budgeted in advance. This results in forecast spend appearing larger than it would at the project level and it also impacts the in-service dates

TAB 14

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 2, Tab 6, Schedule 2, p.285

Question(s):

Enbridge Gas indicates that a technical evaluation has not yet been completed for all system needs in the AMP, and that it will provide an updated version of Appendix B in 2023 to document the progress of IRP evaluations for system needs.

a) Please clarify when this update will be provided, in relation to the schedule for this proceeding.

b) Please confirm that, for all projects in the 2023-2032 AMP that passed the binary IRP screening, Enbridge Gas would complete a technical evaluation of IRPAs, prior to implementing a solution (whether the default facility solution in the AMP or an IRPA). If not confirmed, please provide additional details as to the circumstances under which Enbridge Gas might implement the default facility solution without a technical evaluation of IRPAs, and the number/cost of projects that might be affected.

c) With reference to Appendix B, please provide a list of the projects that would fall into the indicated focus areas used to prioritize technical evaluations (investments with in-service dates of 2028 and prior, with highest costs and/or geographic areas with the highest forecast growth).

Response:

a) Please see Attachment 1 for an updated Appendix B as of March 8, 2023. Enbridge Gas expects to complete the remaining IRP technical evaluations by Q3 2023 for projects that have passed the Binary Screening in the AMP filed Oct 2022 and this analysis will incorporate the Capital Update provided at Exhibit 2, Tab 5, Schedule 4 filed June 16, 2023. /u

b) Confirmed.

TAB 15

Table 4
Customer Attachments by Type Before Energy Transition Impact

	Community Expansion (CE)	Fuel Switching Other than CE	Homes in residential developments (subdivisions)	Single family dwellings (Apartment Ensuite)	Other
2020	564	5,535	30,106	5,305	2,423
2021	428	4,953	33,268	1,741	2,420
2022	314	4,834	30,641	4,279	2,574
2023	579	4,548	30,233	4,282	2,456
2024	1,257	4,640	29,508	4,222	2,342
2025	2,019	4,505	28,841	4,168	2,230
2026	1,802	4,371	28,211	4,119	2,120
2027	1,388	4,229	27,256	4,023	2,015
2028	1,053	4,102	26,057	3,892	1,910
2029	714	3,783	25,301	3,820	1,808
2030	630	3,673	24,567	3,749	1,709
2031	380	3,569	23,854	3,681	1,612
2032	363	3,474	23,166	3,613	1,517

/u

Table 4
Customer Attachments by Type Before Energy Transition Impact

	Community Expansion (CE)	Fuel Switching Other than CE	Homes in residential developments (subdivisions)	Single family dwellings (Apartment Ensuite)	Other
2020	567	5,535	30,106	5,305	2,423
2021	428	4,953	33,268	1,741	2,420
2022	314	4,128	37,583	1,973	2,133
2023	575	3,904	33,285	1,718	2,670
2024	566	3,582	32,761	1,712	2,572
2025	1,115	3,255	33,232	1,686	2,432
2026	1,461	2,904	33,763	1,668	2,338
2027	1,657	2,681	34,238	1,644	2,232
2028	1,574	2,386	34,091	1,592	2,120
2029	1,076	2,168	33,030	1,551	2,030
2030	739	1,918	32,060	1,505	1,897
2031	679	1,674	30,812	1,454	1,814
2032	390	1,519	29,652	1,418	1,742

TAB 16

GEC/ED IR Responses to Staff

N.M9.Staff-1

Ref: Exhibit M9, pp. 42-43, Exhibit I.1.15-ED-84

Energy Futures Group recommends shortening new construction cost recovery periods and reducing infill connection costs funded by rates, to reduce the risk of creating stranded assets should these new customers exit the system prior to the full costs being recovered. This change would generally lead to an increase in upfront connection costs that would need to be paid by new customers (e.g., through a Contribution In Aid of Construction or higher infill connection cost).

a) Does Energy Futures Group believe the same objective (reducing stranded asset risk associated with new customer connections) could also be achieved by: (1) requiring new customers to provide some form of financial assurance in support of the forecast revenue from the customer (as Enbridge Gas has indicated it uses on occasion for larger customers, see I.1.15-ED-84), such that exiting customers would be responsible for an exit fee if leaving the system prior to the cost of their connection being recovered; or (2) by the OEB determining that Enbridge Gas shareholders, not ratepayers, would be responsible for any stranded assets associated with new customer connections? Please comment on the relative merits of the three options to address this risk, including any relevant learnings from other jurisdictions.
b) With either an increased upfront connection cost or a potential exit fee, a challenge is that the entity making the decision as to whether or not to connect to the natural gas system (e.g., a developer) may not be the same as the entity that ultimately pays the higher connection cost or exit fee (the eventual building owner). Does Energy Futures Group have any suggestions as to how to address this challenge, including any relevant learnings from other jurisdictions?

Response:

a) While the risk of stranded assets could be reduced by requiring new customers to pay an "exit fee" if they left the system, that policy would be problematic because it would create disincentives to electrify both now and in the future, even if that is the least cost solution to meeting Ontario's and Canada's greenhouse gas emission reduction goals. Put simply, both the up-front subsidy to connect to the system and the requirement to pay it back later distort market choices. The second alternative of requiring the Enbridge Gas shareholders to be responsible for stranded assets associated with new customers could also reduce ratepayer risk of stranded assets. However, there are still risks in the event that the gas utility goes bankrupt. In addition, if this risk is imposed on Enbridge shareholders it will create huge incentives for the Company to actively discourage customers from leaving the system, even if that was a desirable outcome for both customers and society given climate goals. In addition, it is not clear how either alternative would ensure that new customers make a fair contribution to the rest of the gas system beyond the capital costs for their connection. Thus, the option of reducing current subsidies by shortening new connection cost recovery periods is preferable to the other two options referenced in the question.

b) Mr. Neme does not see an issue with respect to upfront connection costs. While the builder may make the decision about whether to connect, that cost will ultimately be directly passed onto the buyer of the building. The market will then determine the extent to which the higher gas connection fee is "worth it" or, alternatively, whether building an all-electric building is preferable. Put simply, reducing the up-front subsidy by reducing cost recovery periods for new connections will actually reduce current market distortions. With respect to the potential for an "exit fee", the important issue is not that the future building owner may be different than the builder or initial owner who made the decision to connect to the gas system. Rather, as discussed in response to part "a" of this question, the issue is that there will be a disincentive to make a rational economic decision as to whether to stay or exit the gas system. That disincentive will exist despite the fact that the cost of connecting to the system has already been incurred – i.e., it is a "sunk cost". From a societal perspective – the most important perspective for policy-makers – sunk costs should not drive economic decisions.